B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Supplemental Wholesale Power Rate Case
Final Proposal

FY 2009 SECTION 7(b)(2) RATE TEST STUDY

September 2008

WP-07-FS-BPA-14

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FY 2009 7(b)(2) RATE TEST STUDY

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COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COU	Consumer Owned Utility
Con Aug	Conservation Augmentation
C/M	Consumers / Mile of Line for Low Density Discount
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy

DOP	Debt Optimization Program
DROD	Draft Record of Decision
DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatt-hour
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)

IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator
JP	Joint Party
JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company
JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities
JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause

LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
LRA	Load Reduction Agreement
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)
MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWEC	Northwest Energy Coalition
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council

OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PS	Power Services (formerly Power Business Line)
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator

SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively
TS	Transmission Services (formerly Transmission Business Line)
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

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1. INTRODUCTION

Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e(b)(2), directs the Bonneville Power Administration (BPA) to conduct, after July 1, 1985, a comparison of the projected rates to be charged its public body, cooperative, and Federal agency customers for their firm power requirements, over the rate test period plus the ensuing 4 years, with the costs of power (hereafter called rates) to those customers for the same time period if certain assumptions are made. The effect of this rate test is to protect BPA's preference and Federal agency customers' wholesale firm power rates from costs resulting from certain specified provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the loads of Priority Firm Power (PF) preference customers to other BPA firm, adjustable rate loads.

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements of BPA's public body, cooperative, and Federal agency customers (collectively, the 7(b)(2) Customers). The two sets of rates are: (1) a set for the test period and the ensuing four years assuming that section 7(b)(2) is not in effect (known as Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (known as 7(b)(2) Case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from both the Program Case and 7(b)(2) Case rates. Next, each nominal rate is discounted to the beginning of the test period of the relevant rate case. The discounted Program Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the simple average of the Program Case rates is greater than the simple average of the 7(b)(2) Case rates, the rate test triggers. The difference between the average of the Program Case rates and the average of the 7(b)(2) Case rates determines the amount to be reallocated from the 7(b)(2) Customers to other BPA loads in the rate test period.

1.1 Purpose and Organization of Study

The purpose of this Study is to describe the application of the *Section 7(b)(2) Implementation Methodology (Implementation Methodology)* and the results of such application. The accompanying FY 2009 Section 7(b)(2) Rate Test Study Documentation (Documentation), WP-07-FS-BPA-14A, contains the documentation of the computer models and data used to perform the 7(b)(2) rate test.

This Study is organized into three major sections. The first section provides an introduction to the study, as well as a summary of the section *7(b)(2) Legal Interpretation* and *Implementation Methodology*. The second section describes the methodology used in conducting the rate test. It provides a discussion of the calculations performed to project the two sets of power rates that are compared in the rate test. The third section presents a summary of the results of the rate test for the Supplemental Proposal. There are four appendices to the study; Appendix A – Financing Analysis, provides documentation on the financing benefit assumptions , Appendix B – 7(b)(2) Resource Stack tables, provides a copy of the resource stack and GDP inflator/deflator tables for the change in cost of conservation resources for the time value of money, Appendix C - Non-Conservation Resources, provides documentation on the amount and costs of non-conservation resources in the resource stack, Appendix D – Conservation Resources, provides documentation on the amount and cost of conservation resources in the resource stack.

1.2 Basis of Study

1.2.1 Legal Interpretation

Prior to the first phase of the 1985 general rate case, BPA published the *Legal Interpretation of Section 7(b)(2) of the Northwest Power Act*, 49 Fed. Reg. 23,998 (1984). BPA has proposed a revised *Legal Interpretation* as part of the WP-07 Supplemental Proceeding. The revised *Legal Interpretation of Section 7(b)(2) of the Northwest Power Act* is included in this study as Attachment A.

- The 7(b)(2) Case is modeled by limiting the differences between the Program Case and the 7(b)(2) Case to the five assumptions specified in section 7(b)(2) and the secondary effects of those assumptions, and reflecting the effects of these assumptions on the ratemaking processes that remain the same between the Program Case and the 7(b)(2) Case.

- BPA will reallocate costs resulting from the rate test trigger, pursuant to section 7(b)(3) of the Northwest Power Act, in a manner that is consistent with section 7(a) of the Northwest Power Act.

- Applicable 7(g) costs are subtracted from the Program Case and the 7(b)(2) Case rates before those rates are compared.

- “Within or adjacent” direct service industrial (DSI) customer loads are assumed to be served by the 7(b)(2) Customers for the entire rate test period.

- “Within or adjacent” DSI loads assumed to be served by the 7(b)(2) Customers are assumed to be served wholly with firm power purchased from BPA.

- Appendix B to S. Rep. No. 272, 96th Cong., 1st Sess. (1979), is used to determine which DSI loads are "within or adjacent" to 7(b)(2) Customer service areas, with modifications to reflect the actual status, either of BPA service to the DSIs or change of situation in local service area or electrical connection.

- To determine "Federal Base System (FBS) resources not obligated to other entities," DSI loads not "within or adjacent" are assumed to receive service from non-7(b)(2) Customers.

- Section 7(b)(2)(D) identifies three types of additional resources that are assumed, in the 7(b)(2) Case, to meet the 7(b)(2) Customers' loads after the Federal Base System (FBS) resources are exhausted. Specific additional resources are assumed to be used in the order of least cost first; generic resources are then used if necessary.

1.2.2 Implementation Methodology

A hearing pursuant to section 7(i) of the Northwest Power Act was held during 1984 on *Implementation Methodology* issues. The section 7(i) hearing was held as the first phase of the 1985 general rate case. The issues addressed in the hearing are discussed in the *Administrator's Record of Decision for Section 7(b)(2) Implementation Methodology* (7(b)(2) ROD), published in August 1984, and included the adopted *Implementation Methodology*. BPA has proposed a revised *Section 7(b)(2) Implementation Methodology* as part of this WP-07 Supplemental Proposal. The revised *Section 7(b)(2) Implementation Methodology* is included in this study as Attachment B. The major issues resolved in the 7(b)(2) ROD are discussed below.

- Reserve benefits provided under the Northwest Power Act are quantified using the same value of reserves analysis used in the relevant rate case, modified to reflect that "within or adjacent" DSI loads may be less than the total amount of DSI loads served by BPA.

(*See* Wholesale Power Rate Development Study (WPRDS), WP-07-FS-BPA-05, Appendix B.) The proposed *Implementation Methodology* allows for reserves from sources other than DSIs subject to the criteria listed therin. However, within this Supplemental Proposal, reserve benefits provided under the Northwest Power Act are forecast to be zero. These circumstances eliminate the need for a financing benefits analysis to quantify the value of reserves for this rate case.

- Financing benefits in the 7(b)(2) Case are quantified for planned or existing Type 1 or Type 2 resources that have been acquired by BPA or are planned to be acquired in the Program Case during the 7(b)(2) rate test period. The financing benefits in the 7(b)(2) Case are estimated by BPA's Financial Advisor, Public Financial Management, which estimates the sponsor's financial cost for the 7(b)(2) Case resources assuming that BPA did not acquire the resource output. Without the financing benefits that are present in the Program Case, the resources required to meet the 7(b)(2) Customers' loads in the 7(b)(2) Case could be more expensive. When ownership of a resource is by non-preference customers, or is unidentifiable, (Type 3 resources) the proposed *Implementation Methodology* states that the financing benefits analysis does not apply.

- Secondary effects result from reflecting the five specific section 7(b)(2) assumptions in the 7(b)(2) Case rates while keeping all the underlying ratemaking premises and processes the same for both cases. Two secondary effects are identified for possible modeling in the rate test: the level of surplus firm power available, and the amount of marketed secondary energy. The proposed *Implementation Methodology* removes elasticity of demand as a natural consequence.

- The 7(b)(2) rate test in this rate case is conducted using a single automated Excel ® spreadsheet called RAM2007. The outputs of this spreadsheet model are in the FY 2009

Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-14A. The sequence of steps used to conduct the rate test is outlined below in Section 2.1.

- The projected rates for each year of the section 7(b)(2) rate test period is discounted back to the beginning of the rate proposal test period using a factor based on BPA's projected borrowing rate for each of the rate test years. The discounted rates then are averaged for each Case and the result rounded to the nearest tenth of a mill. The rate test triggers if the simple average of the discounted rates for the Program Case exceeds the simple average of the discounted rates for the 7(b)(2) Case by one tenth of a mill or more. If the rate test triggers, the difference between the two rates is multiplied by the projected energy billing determinants of PF Preference customers in the rate period to determine the amount of costs to be reallocated from the preference customers to all other power sales made by BPA in the test year.

2. METHODOLOGY

Implementing section 7(b)(2) consists of incorporating the determinations from the proposed *Legal Interpretation* and proposed *Implementation Methodology* into the RAM2007 model.

2.1 Sequence of Steps

The Rate Design Steps of RAM2007 carry out BPA's ratemaking process by performing the steps needed to develop wholesale power rates and is used as the Program Case for the 7(b)(2) rate test. The 7(b)(2) Case steps of RAM2007 carry out BPA's ratemaking process with changes to reflect the five 7(b)(2) assumptions.

2.1.1 Program Case in RAM2007

RAM2007 calculates annual Program Case rates for the Supplemental Proposal rate period (FY 2009) and the following four years FY 2010-2013. The method of calculating rates and the data used to calculate rates for the Program Case of the 7(b)(2) rate test are identical to those used in calculating the actual proposed rates for the one-year rate period.

2.1.1.1 Sales

The sales forecast used to develop rates for the Program Case covers the period FY 2009-2013, and is the same forecast used to develop BPA's proposed rates. Sales forecasts were developed for the region's consumer-owned utilities (COUs) by aggregating utility-specific forecasts for those customers. The forecast Residential Exchange Program (REP) loads were obtained from the information provided by the utilities. *See* WPRDS, WP-07-FS-BPA-13, Section 8.5.12. For purposes of the 7(b)(2) rate test, BPA is forecasting it will sell no power to the DSIs under the IP rate schedule. Sales to Federal agencies and capacity/energy exchanges are contractually determined and are entered into RAM2007.

BPA's total sales obligations are comprised of COU, investor-owned utility (IOU), DSI, Federal agency, REP, and FPS contractual sales. All PF, IP, and NR forecast sales are entered into RAM2007 with diurnally and seasonally differentiated energy and seasonally differentiated demand billing determinants. Documentation for these forecasts of regional power loads appears in the FY 2009 Load Resource Study, WP-07-FS-BPA-09, and FY 2009 Load Resource Study Documentation, WP-07-FS-BPA-09A, and FY 2009 WPRDS Documentation, WP-07-FS-BPA-13B.

2.1.1.2 Load/Resource Balance

RAM2007 does not perform a Federal system load/resource balance calculation for the Program Case. Instead, the model depends on the load/resource balance performed in the FY 2009 Load

Resource Study, WP-07-FS-BPA-09. Data from the FY 2009 Load Resource Study, WP-07-FS-BPA-09, are used to calculate the energy allocation factors (EAFs) to ensure that resources are allocated to serve loads in the order prescribed by the Northwest Power Act. The FBS serves PF loads (COU, Federal agency, and REP loads) until FBS resources are exhausted. Exchange resources then are used to serve any remaining PF load. DSI, New Resource, and Surplus Firm Power loads are combined into a single rate pool. Remaining REP and new resources are used to serve this combined rate pool.

2.1.1.3 Revenue Requirement

FBS costs are based on the net interest and depreciation associated with the Federal investment in the hydro projects; planned net revenues; hydro operation and maintenance expenses; annual costs related to the Columbia Generating Station, WNP-1 and WNP-3, not including the costs associated with the WNP-3 Settlement Agreement; fish and wildlife costs; costs of the Trojan nuclear plant; costs of hydro efficiency improvements; costs of system augmentation; and costs of balancing purchase power. REP resource costs are based on the average system costs (ASCs) of utilities participating in the REP, including cost adjustments if there are deeming utilities. New resource costs are those of the long-term generating contracts and renewable resources not designated as FBS replacements. Conservation costs include operating expenses, amortization, net interest and planned net revenues associated with the investment in BPA legacy conservation, conservation augmentation, and energy efficiency programs. Other BPA costs include Power Services and agency administrative and general expenses and depreciation, net interest, and planned net revenues associated with Power Services and agency investment in capital equipment. Transmission costs are the annual expenses associated with Power Services' purchase of BPA and non-Federal transmission and ancillary services.

2.1.1.4 Cost Allocation

Allocation of projected costs to customer classes is performed on an average energy basis in RAM2007. Generation costs are allocated by the use of EAFs calculated using the results of the FY 2009 Load Resource Study, WP-07-FS-BPA-09. Conservation and billing credit costs, BPA's administrative and general expenses, and energy service business costs are allocated across all BPA firm loads. The cost allocation procedures for the Program Case are the same as those used to develop BPA's proposed rates. *See generally* FY 2009 WPRDS, WP-07-FS-BPA-13.

2.1.1.5 Rate Design

The adjustments made to allocated costs in RAM2007 for the Program Case are the same as those made to develop BPA's proposed rates. These include adjustments for: (1) secondary and other revenue credits; (2) the surplus firm power revenue surplus/deficiency; (3) the section 7(c)(2) delta and margin; and (4) the DSI floor rate adjustment. These rate design adjustments are discussed below in brief. Fuller descriptions are in the WPRDS, WP-07-FS-BPA-13.

Secondary and Other Revenues are earned from the sale of secondary energy that is made available by the assumption of the average of 50 water years for secondary energy generation capability. Secondary revenues are credited to loads served by FBS and new resources. RAM2007 uses the secondary energy sales revenue forecast produced by the Supplemental Risk Analysis Model (RiskMod), documented in the FY 2009 Risk Analysis Study, WP-07-FS-BPA-12.

The Surplus Firm Power Revenue Surplus/Deficiency results when available surplus firm power is sold at other than its fully allocated cost. In addition, BPA assumes that long-term convertible contracts are in an exchange or power mode depending on the circumstances of the individual contracts. The Supplemental Proposal assumes that all convertible contracts are in the exchange mode. The fully allocated cost of the surplus firm power, less the revenues received from the sale of that power after adjusting for transmission costs, equals the surplus firm power revenue surplus/deficiency. The surplus/deficiency is allocated to firm loads served by FBS and new resources. The revenues from capacity sales are included in the surplus firm power revenue surplus/deficiency and are allocated to all firm loads served by FBS and new resources.

The 7(c)(2) Adjustment is made to account for the difference between the costs allocated to the DSIs and the revenues resulting from the applicable DSI rate. A net margin is used in determining the applicable DSI rate. The net margin subsumes the Value of Reserves credit and the typical margin adjustment. The net margin is 0.573 mills/kWh in nominal dollars.

The DSI Floor Rate test ensures that the DSI rate will not be lower than the IP rate in effect for Operating Year (OY) 1985, pursuant to section 7(c)(2) of the Northwest Power Act. If the IP rate is below that floor rate, the IP rate is raised to the floor rate and an adjustment is necessary to credit additional revenues from the DSIs to other firm power customers.

2.1.2 7(b)(2) Case in RAM2007

The 7(b)(2) Case section of RAM2007 calculates 7(b)(2) Case rates the same way as Program Case rates, except where section 7(b)(2) of the Northwest Power Act requires specific assumptions to be made that modify the Program Case.

2.1.2.1 Sales

The sales forecasts input to RAM2007 to calculate rates for the 7(b)(2) Case are the same sales forecasts used in the Program Case, with the following modifications. The 7(b)(2) Case utility sales are adjusted to exclude estimates of programmatic conservation savings, competitive acquisitions conservation, and billing credits. This upward adjustment in the utility sales forecast includes annual programmatic conservation resources that have an amortized lifetime that includes the rate case test year of FY 2013. Programmatic conservation resources with amortized life times that end before FY 2013 are assumed to be obsolete and have been removed from the 7(b)(2)(D) resource stack and have no effect on the 7(b)(2) sales forecast. The 7(b)(2) Case also excludes REP loads. Sales to "within or adjacent" DSIs, adjusted to exclude estimates of the Conservation/Modernization program, are assumed to be transferred to the service territories of the 7(b)(2) Customers for the entire rate test period as 100 percent firm loads. Sales to DSIs not "within or adjacent" are assumed to transfer to non-7(b)(2) Customers. For the rate test period, no power sales to DSIs are forecast for the Program Case, and thus no DSI loads are added in the 7(b)(2) Case.

2.1.2.2 Resources

The size of the FBS is identical for the Program Case and the 7(b)(2) Case. However, RAM2007 currently models this in such a way that the FBS that is available to serve requirements load is shown as slightly larger in the 7(b)(2) Case. This is because of the treatment of "other obligations" served in the Program Case that were not in existence at the time of the passage of the Northwest Power Act and are not served in the 7(b)(2) Case. If the FBS is insufficient to serve 7(b)(2) Customer loads through the test period in the 7(b)(2) Case, additional resources are assumed to come on-line. Consistent with the Implementation Methodology, three types of additional resources can be added to serve 7(b)(2) Customer loads. Type 1 resources are actual and planned acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case. Type 2 resources are existing resources of 7(b)(2) Customers not dedicated to serving regional loads pursuant to section 5(b) of the Northwest Power Act. These first two types of resources include any BPA programmatic conservation and are used to serve remaining 7(b)(2) Customer load in order of least cost first. Type 3 resources are any additional needed resources priced at the average cost of resources acquired by BPA from non-7(b)(2) Customers consistent with the Program Case. These resources are brought on-line if the first two types of resources are insufficient to meet the 7(b)(2) Customer requirements in the 7(b)(2) Case. Consistent with a proposed clarification in BPA's *Legal Interpretation*, the portions of the Mid-Columbia hydro resources that are contracted to regional IOUs are dedicated to regional loads for purposes of the 7(b)(2) rate test. Therefore, portions of these resources dedicated to regional IOU load are no longer Type 2 resources and have been removed from the 7(b)(2)(D) resource stack.

2.1.2.3 Financing Benefits

The financing benefits analysis required by section 7(b)(2)(E)(i) of the Northwest Power Act was performed by BPA's financial advisor, Public Financial Management. The financial advisor's analysis is Appendix A to this Study. It shows that the estimated financing benefit of BPA's participation in resource acquisitions of BPA-sponsored conservation and generation resources by public utilities is 20 basis points lower than the 7(b)(2) Case without BPA backing using 15-year term financing. For the Cowlitz Falls Project, the estimated benefit of BPA's participation is 5 basis points between an assumed revenue bond issued with and without a BPA contract for the Project. This increases the financing costs for additional resources in the 7(b)(2) Case, thereby increasing the 7(b)(2) Case power cost of the 7(b)(2) Customers.

2.1.2.4 Load/Resource Balance

The 7(b)(2) Case section of RAM2007 adjusts the established load/resource balance from the Program Case to comport with the different loads and resource use restrictions assumed in the 7(b)(2) Case. The Program Case is in load/resource balance during the rate period. The size of the FBS, including the balancing purchase power and augmentation purchase power, are the same in the 7(b)(2) Case as in the Program Case. In addition, the Program Case assumes a small amount of new resources that are not assumed in the 7(b)(2) Case. The 7(b)(2) Customer loads are larger than the Program Case PF loads. In the 7(b)(2) Case, no conservation savings are assumed to have occurred. Other obligations served with FBS resources are slightly smaller in the 7(b)(2) Case because Post Regional Act FPS contracts are assumed not to be served unless there is surplus FBS resource available after 7(b)(2) Customer loads are served. The larger 7(b)(2) Customer loads in the 7(b)(2) Case results in the need to select additional resources from the 7(b)(2)(D) resource stack.

2.1.2.5 Revenue Requirement

The revenue requirement in the 7(b)(2) Case is comprised of the same types of costs and budget information as in the Program Case, with some modifications. The 7(b)(2) Case excludes Program Case revenue requirement amounts for conservation and energy efficiency, billing credits, new resources, and the REP. The only applicable section 7(g) costs that are present in the Program Case revenue requirement are the amounts for conservation and energy efficiency and billing credits. By removing these costs from the initial 7(b)(2) Case revenue requirement, the applicable 7(g) costs have been removed from the 7(b)(2) Case. These applicable 7(g) costs are removed from the Program Case just prior to the two Cases are being compared. This is discussed further in Section 3.3 below. In addition, the contracts excluded from the 7(b)(2) Case (contracts not existing on the effective date of the Act) provide no revenues. Repayment studies are then performed for each year of the 7(b)(2) rate test period using the same procedures as the Program Case.

2.1.2.6 Cost Allocation

7(b)(2) Customers are allocated FBS and resource stack costs according to their use of the respective resources. FBS obligations are allocated costs according to their use of the FBS.

2.1.2.7 Rate Design

Rate design adjustments in the 7(b)(2) Case are performed in the same manner as in the Program Case. However, there is no 7(c)(2) delta or floor rate in the 7(b)(2) Case because there are no DSI loads. Also, the costs of the Conservation Rate Credit (CRC) are not added into the 7(b)(2) Case rates.

3. SUMMARY OF RESULTS

The results for the two Cases are summarized in Tables 1 and 2 below.

3.1 Program Case

The Program Case rate for each year is based on the costs of the resources used to serve the 7(b)(2) Customers. The resource costs are then adjusted as described above and in the FY 2009 WPRDS, WP-07-FS-BPA-13. Table 1 below shows the projection of undiscounted nominal Program Case rates.

3.2 7(b)(2) Case

The annual amount to be paid by 7(b)(2) Customers for their power needs in the 7(b)(2) Case is based on the cost of FBS resources and the cost of additional resources from the 7(b)(2)(D) resource stack. These power costs include adjustments for reserves and financing, *i.e.*, the absence of the reserve benefits and financing benefits implicit in the cost of power in the Program Case. The power costs are then subject to the same cost and revenue adjustment allocations as the Program Case rates. Table 2 below shows the projection of undiscounted nominal 7(b)(2) Case rates.

3.3 The Section 7(b)(2) Rate Test

RAM2007 performs the section 7(b)(2) rate test after it calculates the two sets of test period rates. First, the projected Program Case rates are reduced by the applicable 7(g) costs allocated to the rates for each year. The applicable 7(g) costs are described in section 7(b)(2) as "conservation, resource and conservation credits, experimental resources and uncontrollable events." The applicable 7(g) costs quantified for BPA's rate test are comprised of BPA's acquired and projected conservation, energy efficiency, and CRC costs, and the cost of billing credits. As outlined above in Section 2.1.2.5, applicable 7(g) costs were removed from the 7(b)(2) Case revenue requirement. If there were uncontrollable event costs present in the Program Case revenue requirement, they also would have been excluded from the 7(b)(2) Case revenue requirement. Because these costs are excluded/subtracted from the 7(b)(2) Case at its inception by excluding them from the revenue requirement, there is no need to subtract them at this point in performing the rate test. This explains why "Table 2 - 7(b)(2) Case Rates" does not have an amount of 7(g) costs to be subtracted. The projected rates for each year then are discounted to the beginning of FY 2009 using factors based on BPA's projected borrowing rate for each year. Table 3 shows BPA's forecast borrowing rates that were used in the discounting procedure and the corresponding cumulative discount factors. When applied to the rates in the two Cases, the simple average of the discounted rates over the test period is calculated, rounded to one decimal place, and compared. As shown in Table 4, the rate test triggers by 8.2 mills/kWh. Therefore, a FY 2009 rate adjustment, valued at about $518 million, is required.

TABLE 1
PROGRAM CASE RATES

(Nominal mills/kWh)

Fiscal Year	Rate	Applicable 7(g) Costs	Net Rate
2009	34.48	1.47	33.01
2010	35.53	1.67	33.86
2011	37.66	1.75	35.91
2012	36.56	1.67	34.89
2013	37.70	1.76	35.94

TABLE 2
7(b)(2) CASE RATES

(Nominal mills/kWh)

Fiscal Year	7(b)(2) Rate
2009	21.58
2010	24.47
2011	27.53
2012	24.51
2013	26.26

TABLE 3
DISCOUNT FACTORS FOR THE RATE TEST

Fiscal Year	Annual BPA Borrowing Rate[1]	Cumulative Discount Factor[2]
2009	.0654	.9386
2010	.0678	.8790
2011	.0684	.8227
2012	.0684	.7700
2013	.0673	.7214

[1] Final Revenue Requirement Study Documentation, WP-07-E-BPA-02A, Chapter 6.
[2] $DiscFact_t = DiscFact_{t-1}/(1 + BorrowRate_t)$; Fiscal Year 2008 equals 1.

TABLE 4
COMPARISON OF RATES FOR TEST

(Discounted mills/kWh)

Fiscal Year	Discounted Program Case Rate	Discounted 7(b)(2) Case Rate
2009	30.98	20.25
2010	29.76	21.51
2011	29.54	22.65
2012	26.87	18.87
2013	25.93	18.94
Average Rate	28.6	20.4

Difference of Average Rates 8.2

Attachment A

Legal Interpretation of Section 7(b)(2) of the
Pacific Northwest Power Planning and Conservation Act

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B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

SECTION 7(b)(2) OF THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT

LEGAL INTERPRETATION

September 2008

WP-07-A-06

DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act

I. Background

A. Relevant Statutory Provisions

The Administrator of the Bonneville Power Administration (BPA) is charged with the responsibility of implementing section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §§ 839, *et seq*. An agency's interpretation of the statute it is charged to administer is entitled to great deference; in particular, the United States Supreme Court has held that "it is clear that the Administrator's interpretation of the Regional [Northwest Power] Act is to be given great weight." *Aluminum Co. of America v. Central Lincoln Peoples' Util. Dist.*, 467 U.S. 380, 389 (1984).

Basic principles of statutory construction must be followed in interpreting the Northwest Power Act. These principles require that particular provisions of a statute be interpreted to give effect to its overall purposes. *United States v. Am. Trucking Ass'n*, 310 U.S. 534, 543 (1950). Wherever possible, statutory provisions should be construed so as to be consistent with each other. *Adams v. Howerton*, 673 F.2d 1036, 1040 (9th Cir. 1982), *cert. denied*, 458 U.S. 1111 (1982). Thus, BPA interprets the Northwest Power Act in a manner which seeks consistency among the requirements of each section of the Northwest Power Act.

In addition to the Northwest Power Act, BPA is responsible for establishing rates pursuant to the Bonneville Project Act. 16 U.S.C. § 832, *et seq.*, the Federal Columbia River Transmission System Act, 16 U.S.C. § 838, *et seq.*, and the Flood Control Act of 1944, 16 U.S.C. § 825, *et seq.* These statutes require BPA to set rates, in accordance with sound business principles, at levels sufficient to recover BPA's total system costs, including repayment of the Federal Treasury investment in the Federal Columbia River Power and Transmission System over a reasonable number of years. All statutory provisions concerning the timely recovery of BPA's revenue requirement are relevant to the interpretation of the Northwest Power Act. For "[w]hen there are two acts upon the same subject, the rule is to give effect to both if possible." *Morton v. Mancari*, 417 U.S. 535, 551 (1974), *quoting United States v. Borden Co.*, 308 U.S. 188, 198 (1939).

Section 7 of the Northwest Power Act, 16 U.S.C. § 839e, contains a number of directives that the BPA Administrator must consider in establishing rates for the sale of electric energy and capacity and for the transmission of non-Federal power. Section 7(b)(2), commonly referred to as the "rate test," is one of these directives. Section 7(b)(2) of the Northwest Power Act, 16 U.S.C. § 839e(b)(2), provides:

After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative, and Federal agency customers exclusive of amounts charged such customers under subsection 7(g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that –

(A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are

(i) served by the Administrator, and

(ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

(B) public body, cooperative, and federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980, (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;

(C) no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period;

(D) all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were –

(i) purchased from such customers by the Administrator pursuant to section 6, or

(ii) not committed to load pursuant to section 5(b),

and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and

(E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from –

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under this Act

were not achieved.

16 U.S.C. § 839e(b)(2).

B. Scope of Interpretation

This Legal Interpretation resolves only the basic legal issues necessary to implement section 7(b)(2) and modifies the first Legal Interpretation issued June 8, 1984. *See* Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 49 Fed. Reg. 23,998 (June 8, 1984).

II. Interpretation

A. Definitions

This section contains definitions applicable to section 7(b)(2). Terms identified in the Northwest Power Act have the same meaning in this interpretation, unless further defined.

1. <u>Relevant Rate Case</u>: The section 7(i) wholesale power rate adjustment proceeding being conducted at the time the projections for section 7(b)(2) are made, and in which any adjustment to rates in accordance with section 7(b)(2) may be reflected.

2. <u>General Requirements</u>: The public body, cooperative, and Federal agency customers' electric power assumed in the Relevant Rate Case to be purchased from BPA, exclusive of new large single loads. General Requirements are limited to power purchased from BPA under section 5(b) of the Northwest Power Act; section 5(c) purchases from BPA are not included.

3. <u>7(b)(2) Customers</u>: Those firm power customers of BPA that are listed in section 7(b)(2) of the Northwest Power Act as subject to the rate test, *viz.*, public bodies, cooperatives, and Federal agencies.

4. <u>Applicable 7(g) Costs</u>: The costs identified in section 7(g) of the Northwest Power Act that are also listed in section 7(b)(2), *viz.*, costs chargeable to 7(b)(2) Customers for conservation, resource and conservation credits, Experimental Resources, and Uncontrollable Events.

5. Uncontrollable Event: A discrete event which differs from the continuum of changing events that occur in nature, business, and government (such as changes in water conditions, aluminum prices, and electricity markets) and that are routinely reflected in ratemaking.

6. Experimental Resources: Resources that are undergoing research and development and are funded by BPA in full or in part.

7. Five-Year Period: The rate recovery period of the Relevant Rate Case, plus the ensuing four years. If the Relevant Rate Case has more than a one-year rate recovery period, the Five-Year Period will be greater than five years.

8. Program Case: The entire process of calculating rates to be charged in the Five-Year Period of the Relevant Rate Case under the provisions of the Northwest Power Act other than section 7(b)(2), including all specific data, assumptions, and results.

9. 7(b)(2) Case: The entire process of calculating rates for the relevant Five-Year Period under the provisions of section 7(b)(2) of the Northwest Power Act, including all specific data, assumptions, and results.

10. Five Assumptions: The five differences between the Program Case and the 7(b)(2) Case specified in subsections (A) through (E) of section 7(b)(2) of the Northwest Power Act.

11. DSI Loads: Those loads of direct service industries (DSIs) that are forecast to be served by BPA, during the Five-Year Period, pursuant to section 5(d)(1) or 5(f) of the Northwest Power Act.

12. Within or Adjacent: Relating to DSI customer loads determined in accordance with section 7(b)(2)(A) to be electrically within or adjacent to the geographic service territories of 7(b)(2) Customers.

13. Quantifiable Monetary Savings: The change in annual costs attributable to differences in resource financing or Reserve Benefits.

14. Reserve Benefits: The annual financial value of (1) resources designated by BPA as providing reserves, or (2) interruptible load that forestalls a resource acquisition by virtue of the ability to curtail the load at a time when off-line generation would otherwise need to be available to start up and serve load during unexpected conditions.

B. General Approach and Specific Issues of Interpreting Section 7(b)(2)

Section 7(b)(2) assures that 7(b)(2) Customers are charged no more for their General Requirements after July 1, 1985, than they would have been charged if the Five Assumptions were to be realized. These assumptions direct BPA to hypothesize power supply arrangements between itself and its customers that are quite different from reality. Implementation of the Five

Assumptions listed in section 7(b)(2) is by nature an exercise in speculation. This interpretation was undertaken to reduce this inherent speculation insofar as possible.

1. Interpretation: Section 7(b)(2) limits the 7(b)(2) Case to the Five Assumptions listed in section 7(b)(2) and the secondary effects of those assumptions.

Discussion:

The Northwest Power Act provides that after July 1, 1985, the 7(b)(2) Customers' power costs "may not exceed … as determined by the Administrator" the power costs for General Requirements based on the enumerated Five Assumptions. 16 U.S.C. § 839e(b)(2). This language grants the Administrator discretion to determine the manner in which the Five Assumptions of section 7(b)(2) are applied and the rate test is implemented. However, BPA recognizes that the reasonableness of methodologies used to implement section 7(b)(2) will be tested in the Relevant Rate Case.

The Administrator will exercise his discretionary authority in the following manner. Except for the Five Assumptions specified in section 7(b)(2), all underlying premises will remain constant between the Program Case and the 7(b)(2) Case. Assumptions not specified by the statute will not be considered. Secondary effects, however, of the Five Assumptions will be given full recognition in the modeling of the 7(b)(2) Customers' power costs in the 7(b)(2) Case. This general approach will allow the 7(b)(2) Case to be modeled under the same accepted ratemaking techniques used in the Program Case. This approach will also avoid the modeling of a hypothetical world that attempts to reflect in extreme detail what would have occurred had the Northwest Power Act not been enacted.

The legislative history of the Northwest Power Act supports limiting the assumptions of the 7(b)(2) Case to those specified in the statute. The House Committee on Interstate and Foreign Commerce Report accompanying S. 885 (the bill that became the Northwest Power Act) notes that "[t]he assumptions to be made by the Administrator in establishing this ceiling are specifically set forth." H. Rep. No. 976-I, 96th Cong., 2d Sess. 68 (1980). Similarly, the Report of the House Committee on Interior and Insular Affairs declares that "[s]ubsection 7(b)(2) establishes a 'rate ceiling' for BPA's preference customers, and specifies the method of calculating this ceiling…" H. Rep. No. 976-II, 96th Cong., 2d Sess. 52 (1980).

Legislative history also supports including the unavoidable secondary effects of the assumptions listed in the Northwest Power Act. In particular, in addressing Reserve Benefits, Appendix B to the Report of the Senate Committee on Energy and Natural Resources provides that in addition to costs specifically described in sections 7(b)(2)(B) and (D), the Administrator is to consider "[a]ny other general system operating costs, including reserves…" S. Rep. No. 272, 96th Cong., 1st Sess. (1979), Appendix B, at 58.

As an illustration of the secondary effects referred to above, BPA identified two secondary effects of the Five Assumptions found in section 7(b)(2) in its 1984 Legal Interpretation that continue to be relevant. These effects involve surplus levels and secondary energy markets. The secondary effects must be included in section 7(b)(2) methodologies as natural consequences of the Five Assumptions in section 7(b)(2) on the results of underlying premises that are held constant between the Program Case and the 7(b)(2) Case. Surplus levels and the secondary energy market must change as a natural consequence of the Five Assumptions. As the DSIs are assumed to shift to the private utilities and 7(b)(2) Customers under section 7(b)(2), BPA's load/resource balance changes. This change will affect the level of BPA's surplus. The secondary energy market will also change; the top quartile of DSI Loads will not be served by BPA's secondary energy. Any additional secondary effects will be identified by BPA in the relevant rate case.

Section 7(b)(2) requires BPA to assume that the 7(b)(2) Case is identical to the Program Case except for those differences required by the Five Assumptions set out in section 7(b)(2)(A)-(E) and the secondary effects. Present modeling techniques used in the Program Case, which will be used in the modeling of the 7(b)(2) Case, incorporate secondary effects.

2. Interpretation: Implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a).

Discussion:

BPA will conscientiously follow the requirements of section 7(b)(2) to perform the "rate test" for its public body, cooperative, and Federal agency customers. If the results of the rate test indicate that BPA must recover costs in excess of those allowed under section 7(b)(2), BPA will implement the section 7(b)(3) supplemental rate charge provision for that purpose. BPA's concern is that failure to recover some, or all, of the reallocated costs "through supplemental rate charges for all other power sold by the Administrator to all customers" may result in BPA's inability to meet the requirements of section 7(a). Such a determination, if it occurs, would be rigorously documented and exposed to careful review during the section 7(i) process for the Relevant Rate Case. Should this occur, BPA would be forced to resolve a possible conflict among sections 7(b)(2), 7(b)(3), and 7(a).

Section 7(a) of the Northwest Power Act requires that BPA rates recover the costs of the electric power and transmission systems, including the repayment of Federal Treasury investments in those systems. Section 7(a) reaffirms this longstanding obligation which was articulated earlier in the Bonneville Project Act and the Federal Columbia River Transmission System Act. Section 7(b)(2) must be applied in a manner which enables BPA to set rates at levels sufficient to recover costs, or the rates will not receive confirmation and approval from the Federal Energy Regulatory Commission. *See* 16 U.S.C. § 839e(a)(2).

The legislative history of the Northwest Power Act supports application of section 7(b)(2) in a manner consistent with BPA's primary statutory obligation that its rates recover costs. The House Interior Committee report declares that:

> Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customers under this legislation. Subject to the

> general requirement (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs, BPA is required by the legislation to establish the following rates: [report continues by setting out rate structure of the Act].

H. Rep. No. 976-11, 96th Cong., 2d Sess. 36 (1980).

Section 7(a)(2) illustrates the importance of BPA's statutory obligation to set rates at levels sufficient to collect its costs. Section 7(a)(2) states that FERC cannot approve BPA's rates unless the rates "are sufficient to assure repayment of federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs," 16 U.S.C. § 839e(a)(2)(A), and "are based upon the Administrator's total system costs …" 16 U.S.C. § 839e(a)(2)(B). Indeed:

> BPA is a self-financed agency under the terms of the Federal Columbia River Transmission System Act of 1974. This means that BPA receives no appropriations. It is required by law to cover its full costs through its own revenues derived from the sale of power and other services. … The United States of America does not stand behind BPA's obligations. … BPA alone must meet these obligations, and BPA's rates cannot be approved by FERC unless they are sufficient to meet these obligations.

126 Cong. Rec. H9843 (daily ed. Sep. 29, 1980) (statement of Rep. Ullman).

BPA is neither predetermining the results of the rate test nor suggesting a disregard for section 7(b)(2) with this discussion. BPA is not suggesting a solution to any problem arising from a potential conflict among sections 7(a), 7(b)(2), and 7(b)(3). BPA is merely attempting through this interpretation to alert its customers and the public to one possible problem which may present itself in the future.

3. Interpretation: Applicable 7(g) Costs are to be excluded from the Program Case rates and the 7(b)(2) Case rates prior to comparison with the 7(b)(2) Case rates.

Discussion:

Section 7(b)(2) states: "… the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total … an amount equal to the power costs for general requirements of such customers if, the Administrator assumes …" the Five Assumptions. 16 U.S.C. § 839e(b)(2).

The foregoing language describes the basic comparison of the Program Case and the 7(b)(2) Case in performing the section 7(b)(2) rate test. In particular, it sets forth the instructions on how BPA is to initially construct the two revenue requirements that will serve as the foundation of the rate test comparison. The language begins with the Program Case. The revenue requirement in the Program Case rate is to be constructed from the "projected amounts to be charged for firm power" for the "general requirements" of BPA's preference customers. This phrase refers to the firm power costs BPA is proposing to recover through its 7(b) rates. Thus, BPA is to start with its total revenue requirement in the Program Case.

The statutory language further directs BPA to modify this revenue requirement by excluding "the amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events …" In other words, BPA must subtract the identified 7(g) costs (referred to hereafter as Applicable 7(g) Costs) from the Program Case revenue requirement. This reduces the revenue requirement in the Program Case, resulting in the power costs to be recovered in the Program Case.

The second half of the above-noted language then describes how BPA is to initially construct the revenue requirement in the 7(b)(2) Case. Specifically, the 7(b)(2) Case revenue requirement is equal to "the power costs for general requirements of such customers …" as modified by the Five Assumptions. The phrase "power costs for general requirements of such customers" is a direct reference back to the "projected amounts to be charged" when calculating the costs of the Program Case. Because the two clauses are identical in all material respects, the same power costs that were used to serve the "general requirements" in the Program Case should be used as the starting point to construct the revenue requirement for the 7(b)(2) Case; that is, "the projected amounts to be charged for firm power, subject to the Five Assumptions and their secondary effects."

This interpretation, in addition to being consistent with the aforementioned statutory text, also makes practical sense when actually implementing the 7(b)(2) rate test. First, having symmetry between the initial revenue requirements in the Program Case and the 7(b)(2) Case ensures that the later application of the Five Assumptions and their secondary effects is the central reason the rate test triggers or fails to trigger. Congress specifically identified the Five Assumptions as the factors the Administrator was to "assume" in determining the power costs in the 7(b)(2) Case. By limiting the cost differences between the Program Case and the 7(b)(2) Case before the application of these assumptions, BPA can give the full and proper effect to the rate test construct envisioned by Congress. Without this symmetry, the rate test results may become skewed by factors other than the Five Assumptions and their secondary effects. For example, if Applicable 7(g) Costs were excluded from the Program Case (making it less expensive), but included in the 7(b)(2) Case (making it more expensive), it could create a cost incongruity that could become a determinative factor in whether the rate test will trigger. Having an equilibrium between the costs in the Program Case and the 7(b)(2) Case reduces these unintended consequences and preserves the Congressionally identified drivers of the rate test – the Five Assumptions and their secondary effects.

Second, this interpretation also avoids potential conflicts with the remaining sections of the 7(b)(2) rate test. Specifically, if the "power costs" used in the 7(b)(2) Case were not interpreted to mean the same power costs in the Program Case, exclusive of costs related to the Five Assumptions and their secondary effects, a conflict would occur between the above-mentioned paragraph and section 7(b)(2)(D)(i), the fourth of the Five Assumptions. The fourth assumption specifies that any remaining General Requirements in the 7(b)(2) Case that have not been satisfied by Federal Base System (FBS) resources pursuant to the second assumption (*i.e.*, section 7(b)(2)(B)) are met with resources taken from a resource stack developed in accordance with subsection 7(b)(2)(D). *See* Issue 11, *infra*.

Section 7(b)(2)(D) provides that, in conducting the 7(b)(2) test, the Administrator is to assume that:

> all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were –
>
> (i) purchased from such customers by the Administrator pursuant to section 6, or
>
> (ii) not committed to load pursuant to section 5(b),
>
> and were the least expensive resources owned or purchased by public bodies and cooperatives; and any additional needed resources were obtained at the average cost of all other resources acquired by the Administrator…

16 U.S.C. § 839e(b)(2)(D). Resources that meet the criteria identified in section 7(b)(2)(D) are assumed to be in a "resource stack," available for use to serve the General Requirements of the 7(b)(2) Customers in the 7(b)(2) Case. This resource stack includes three types of resources. Type 1 resources are resources the Administrator acquired or plans to acquire from 7(b)(2) Customers pursuant to section 6 of the Northwest Power Act. Type 2 resources are not committed to load pursuant to section 5(b). Type 3 resources are any remaining needed resources. *See* Issue 11, *infra*. It is the Type 1 resources that create an anomaly in the treatment of 7(g) costs.

When resources are included in the resource stack, they are not used to serve General Requirements in the 7(b)(2) Case unless needed and selected from the stack. Section 7(b)(2)(D) refers to "resources … purchased from such [7(b)(2)] customers by the Administrator pursuant to section 6 [of the Northwest Power Act]." *Id.* Conservation is a resource that is assumed to be available in the resource stack. The Northwest Power Act specifically defines conservation as a resource:

> "Resource" means – electric power, including the actual or planned electric power capability of generating facilities, or actual or planned *load reduction resulting from* direct application of a renewable energy resource by a consumer, or from *a conservation measure*.

16 U.S.C. § 839a(19) (emphasis added). Furthermore, conservation is acquired pursuant to section 6 of the Act. Section 6 provides, *inter alia*, that "[t]he Administrator shall acquire such resources through conservation …" 16 U.S.C. § 839d(a)(1). The term "such resources" refers to resources sufficient to meet the Administrator's contractual obligations under section 5 to

provide electric power to meet firm power loads. Therefore, conservation is a Type 1 resource and must be included in the resource stack.

Conservation resources and billing credit resources, however, can only be included in the resource stack if Applicable 7(g) Costs are removed from the starting 7(b)(2) Case revenue requirements. Recall that the Applicable 7(g) Costs exclude the cost "*of conservation, resource and conservation credits*, experimental resources and uncontrollable events …" 16 U.S.C. § 839e(b)(2) (emphasis added). The import of leaving the Applicable 7(g) Costs in the 7(b)(2) Case is that the costs of "conservation, resource and conservation credits" will remain in the 7(b)(2) revenue requirement. With conservation costs already in the costs of the 7(b)(2) Case, there is no logical way for conservation resources to be available *again* in the resource stack. To do so would be to effectively double-count the conservation costs – first in the 7(b)(2) revenue requirement (because they were never taken out), and second as the costs of a Type 1 resource (assuming it is selected). The only way to avoid this double-counting is to either remove the conservation costs from the 7(b)(2) Case revenue requirement *or* remove conservation resource costs from the resource stack.

In BPA's view, the more appropriate alternative is the former. Treating conservation as a Type 1 resource gives full effect to section 7(b)(2)(D)(i). The Administrator will be fulfilling the Congressional mandate to include resources in the 7(b)(2) Case resource stack "purchased from such customers by the Administrator pursuant to section 6 …"; *e.g.*, conservation resources. 16 U.S.C. § 839e(b)(2)(D)(i). By contrast, the latter alternative of removing all conservation costs from the resource stack would completely frustrate the purpose of referring to section 6 resources in section 7(b)(2)(D)(i). This is also consistent with the lack of "exclusive of" language after the reference in section 7(b)(2) to "power costs for general requirements of such customers …" The better interpretation is therefore to include conservation as a Type 1 resource. To effectuate this interpretation, Applicable 7(g) Costs, which include conservation costs, must be removed from the 7(b)(2) Case revenue requirement.

In summary, BPA will interpret the aforementioned statutory language as meaning that the Program Case and 7(b)(2) Case must begin with the same power costs, exclusive of costs related to the Five Assumptions and their secondary effects. That is, the costs of resources associated with the Applicable 7(g) Costs will be excluded from the 7(b)(2) Case power costs through application of the Five Assumptions. The Applicable 7(g) Costs will be excluded from the Program Case rates prior to comparison with the 7(b)(2) Case rates. This interpretation is consistent with the statutory language and the purpose of the section 7(b)(2) rate test. It also avoids unnecessary conflicts with, and gives full effect to, the other provisions of section 7(b)(2).

4. Interpretation: The appropriate Five-Year Period is the rate recovery period for the applicable rate case plus the ensuing four years.

Discussion:

Section 7(b)(2) states: "… during any year after July 1, 1985, plus the ensuing four years, …" and several times thereafter "… during such five-year period …" "Any year," in this context, refers to the period of time applicable to the opening statement of section 7(b)(2); namely, the period over which "the projected amounts to be charged for firm power" are applicable, otherwise known as the revenue recovery period.

BPA has had varying lengths of revenue recovery periods in the 22 years between July 1, 1985, and October 1, 2007. Four times BPA has used two-year periods, twice BPA has used five-year periods, once for one year, once for three years, and once for 27 months. In each of these periods, the rate test was performed on the basis that the revenue recovery period was the "first year" of the Five-Year Period. For each of these rate tests, the four years subsequent to the last year of the revenue recovery period were appended to form the Five-Year Period.

It is reasonable to consider that the Five-Year Period might encompass more than 60 months. As noted above, the rate test is to compare the projected amounts to be charged for firm power. In the instance of a revenue recovery period that encompasses more than 12 months, the projected amounts to be charged are developed for the entire revenue recovery period. Therefore, to be consistent with the development of the amounts to be charged, it is reasonable to consider that time period, be it 12 months or more, the first year of the period of consideration for the rate test.

5. Interpretation: 7(b)(2) Customers' loads include DSI Loads that are Within or Adjacent to the 7(b)(2) Customers' service territories.

Discussion:

Section 7(b)(2)(A) provides that BPA is to assume that "the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are: (i) served by the Administrator, and (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives …" 16 U.S.C. § 839e(b)(2)(A). The plain language of section 7(b)(2)(A) requires the Administrator to assume that 7(b)(2) Customers' loads include any Within or Adjacent DSI Loads during the Five-Year Period.

The legislative history of the Northwest Power Act also supports BPA's interpretation of the statute. In the analysis of the section 7(b)(2) directives contained in Appendix B to the Senate Report, S. Rep. No. 272, 96th Cong., 1st Sess., at 65-79 (1979), forecast DSI Loads were transferred from BPA to 7(b)(2) Customers for the entire test period regardless of contracts in effect as of the effective date of the Northwest Power Act. In the projections contained in Appendix B, calculations of public agency loads for the 7(b)(2) Case included a full 85 percent of projected DSI Loads beginning in 1980 (85 percent was the amount determined to be "Within or Adjacent" to preference agency service areas). Although Appendix B is not conclusive evidence of legislative intent, it was "an important part of the common understanding about how the costs of resources would be distributed as a result of [the Northwest Power Act]." *Id.* at 31. Appendix B is a useful tool for statutory construction where it speaks directly to an issue and does not conflict with the language of the statute.

6. Interpretation: BPA will use Appendix B of the Senate Report to assist in determining which DSI Loads are Within or Adjacent to the geographic service boundaries of 7(b)(2) Customers.

Discussion:

Section 7(b)(2)(A) requires the Administrator to assume that during the relevant Five-Year Period, "the public body and cooperative customers' general requirements had included … the direct service industrial customer loads which are … located within or adjacent to the geographic service boundaries of such public bodies and cooperatives …" 16 U.S.C. § 839e(b)(2)(A). It is not apparent from the statute how BPA is to resolve the question of which DSIs are Within or Adjacent to public body and cooperative customers' boundaries. Therefore, BPA must look to legislative history to resolve the ambiguity.

The legislative history of the Northwest Power Act indicates that a determination of which DSIs are Within or Adjacent to public body and cooperative customers' boundaries was made in Appendix B. S. Rep. No. 272, 96th Cong., 1st Sess., Appendix B, at 66. Appendix B includes a table listing the DSIs "within BPA preference customers' service areas," DSIs "adjacent to BPA preference customers' service areas," and those DSIs that "could not readily be served by BPA preference customers." *Id.*

The Within or Adjacent table in the numerical analysis in Appendix B is accompanied by a narrative explanation which states that the loads for establishing resource requirements under section 7(b)(2) will include "DSI total loads within or adjacent to the service territory of the public bodies and cooperatives. (85 percent of existing DSIs as shown in the attached table)." *Id.* at 58. The clear and detailed nature of the Within or Adjacent table and the narrative explanation in Appendix B convince BPA that Congress intended the Appendix B table to be used in resolving which DSIs are Within or Adjacent to the service territories of public body and cooperative customers. The Appendix B table will be disregarded only if conditions of service to those DSI customers change, such as in the case of termination of BPA service to a DSI industrial plant, or if the location of the DSI changes from an IOU service territory to a public utility service territory.

Adjacent will be assessed on electrical connections rather than a strictly locational basis. Circumstances may occur where a DSI's location may be outside of a 7(b)(2) Customer's service territory, but a direct electrical connection exists between the DSI and the 7(b)(2) Customer. Conversely, a DSI's location may be inside a 7(b)(2) Customer's service territory, but no direct electrical connection exists between the DSI and the 7(b)(2) Customer. This determination will consider normal operating electrical connections and disregard emergency connections.

7. Interpretation: All DSI Loads assumed to be placed on 7(b)(2) Customers will be treated as firm loads.

Discussion:

Section 7(b)(2)(A) provides that BPA is to assume "that the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customers loads …" 16 U.S.C. § 839e(b)(2)(A). Section 7(b)(2)(A) does not expressly state the nature or quality of service assumed to be provided by the public bodies and cooperatives to the relevant DSI Loads.

The DSI Loads originally served by BPA under the Northwest Power Act included three quartiles that were firm loads and one quartile (the first quartile) that BPA did not plan or acquire resources to serve. However, the language of the Act is compelling that Congress intended all relevant DSI Loads, assumed to be served by public bodies and cooperatives, to be treated as firm.

Section 7(b)(2)(A) requires BPA to assume that the loads of relevant DSIs are included in the 7(b)(2) Customers' "general requirements," a term defined by section 7(b)(4) of the Northwest Power Act as limited to electric power purchased from the Administrator under section 5(b) of the Act. Section 5(b) deals exclusively with firm power. In addition, section 7(b)(2)(B) requires the Administrator to assume that public body, cooperative, and Federal agency customers are served first with the FBS resources, and section 7(b)(2)(D) requires that additional resources be assumed to serve the remaining general requirements of the 7(b)(2) Customers.

The legislative history of the Northwest Power Act supports interpreting the statute to require 7(b)(2) Customers' firm power General Requirements in the 7(b)(2) Case to include all DSI Loads served by the Administrator. This includes DSI Loads that BPA does not plan or acquire resources to serve (*e.g.*, first-quartile service) in the Program Case. In Appendix B, all four quartiles of DSI Loads were treated as firm when assigned to public agency customers in the 7(b)(2) Case.

8. Interpretation: Section 7(b)(2)(B) necessitates an examination of Program Case contracts in the determination of "Federal base system resources not obligated to other entities."

Discussion:

Section 7(b)(2)(B) provides that the Administrator is to assume that 7(b)(2) Customers were served by FBS resources "not obligated to other entities under contracts existing as of December 5, 1980 (during the remaining term of such contracts), excluding obligations to direct service industrial customer loads included in [Section 7(b)(2)(A)])." 16 U.S.C. § 839e(b)(2)(A). Unlike the assumption relating to DSI Loads served by public body and cooperative customers, section 7(b)(2)(B) requires BPA to make two factual determinations: (1) what the level of FBS resources is, and (2) what level of FBS resources is obligated for service to other entities, for all or a portion of the relevant Five-Year Period. The first determination is necessary because the FBS includes resources purchased by BPA under long-term contracts. Expiration of these contracts may cause a change in the size of the FBS during the relevant Five-Year Period.

The second determination concerns BPA power sales contracts or other obligations existing as of the effective date of the Northwest Power Act. Should these contractual obligations on FBS resources be removed through expiration of the relevant contracts, the size of FBS resources available to 7(b)(2) Customers would increase. Obligations on FBS resources include uses of power mandated by treaty, statute, or contracts entered into by BPA before December 5, 1980. The DSI obligations referenced in subsection 7(b)(2)(B) have since expired, rendering the "excluding obligations" language no longer effective.

Any contract that BPA enters into subsequent to December 5, 1980, that exchanges FBS capacity for energy, exchanges seasonal FBS energy, or for the sale of FBS capacity with the return of the energy, will be assumed only if there is FBS surplus to 7(b)(2) Customer needs. Therefore, the energy and revenue from such contracts will not be recognized in the 7(b)(2) Case unless, and to the extent that, there is surplus FBS in the 7(b)(2) Case.

9. Interpretation: Section 7(b)(2)(B) requires the allocation of resource pools to load pools in the Program Case to be reconsidered in the 7(b)(2) Case.

Discussion:

Section 7(b)(2)(B) states that the Administrator is to assume that "public body … customers were served … with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980 … excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph." 16 U.S.C. § 839e(b)(2)(B).

In the Program Case, section 7(b)(1) sets forth the sequence of allocating resource pools to load pools.

> Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) and then from other resources.

The resource cost allocation hierarchy established by section 7(b)(1), and complemented for other rates in sections 7(c)(1)(A) and 7(f), is that the FBS is to be used first to serve 7(b) loads, then for 7(c) loads and 7(f) loads until the FBS resources are exhausted. After the FBS resources are exhausted, BPA uses power acquired from the section 5(c) exchange to serve remaining loads. After using FBS and exchange resources, other resources acquired by BPA, also referred to as new resources, are used to serve remaining loads.

The Program Case uses this resource cost allocation hierarchy to apply the resource pools, and their costs, to the load pools as the method of assigning resource costs to the load pools. However, in the 7(b)(2) Case, the size of the load pools will be different than in the Program Case. For example, section 5(c) exchange loads are removed from the 7(b)(2) Case load pool, thereby creating a smaller 7(b) load pool in the 7(b)(2) Case.

As a result of the different sizes of load pools in the two cases, the 7(b)(2) Case must construct its own separate allocation of resource pools to load pools. Furthermore, because of the explicit exclusion of the section 5(c) exchange in the 7(b)(2) Case, the exchange resource pool is eliminated. Lastly, because additional resources necessary in the 7(b)(2) Case are to be added through the 7(b)(2)(D) resource stack, the new resource resource pool is eliminated from the 7(b)(2) Case. All of these differences will result in different resource cost allocations than in the Program Case.

10. Interpretation: Section 7(b)(2)(C) requires the exclusion of all costs relating to the section 5(c) exchange, otherwise known as the Residential Exchange Program, from the 7(b)(2) Case. In addition, the loads and resources associated with the exchange will also be excluded from the 7(b)(2) Case.

Discussion:

Section 7(b)(2)(C) states that the Administrator is to assume that "no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period." 16 U.S.C. § 839e(b)(2)(C). This language unmistakably provides that the 7(b)(2) Case is to assume that the Residential Exchange Program is to be excluded from consideration. This includes all aspects of the exchange: the costs, the purchases, and the sales. Further, any implementation costs included in the Program Case should be excluded from the 7(b)(2) Case, as should any costs associated with a settlement of residential exchange benefits.

11. Interpretation: Section 7(b)(2)(D) identifies three additional resource types assumed to be available to meet the 7(b)(2) Customers' Remaining General Requirements when FBS resources are exhausted. Type 1 are those resources not included in the FBS that are actually acquired by BPA from 7(b)(2) Customers in the Program Case. Type 2 are those resources owned or purchased by the 7(b)(2) Customers and not dedicated to load by public agencies or investor-owned utilities pursuant to section 5(b). These two types of resources are to be stacked in order of cost and then pulled from the stack to meet 7(b)(2) Customers' loads as needed, least expensive first. Type 3 resources are additional acquired resources not included in the FBS, which are priced at the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the Five-Year Period.

Discussion:

Section 7(b)(2)(D) describes the manner in which additional resources are assumed to be acquired to meet the 7(b)(2) Customers' loads when FBS resources are exhausted. Three types of additional resources are available in the 7(b)(2) Case. The first type of resource is described in section 7(b)(2)(D)(i) as being resources that were "purchased from such customers by the Administrator pursuant to section 6." These are the resources actually acquired by BPA from the 7(b)(2) Customers in the Program Case.

Conservation is defined in the Northwest Power Act as a resource. "'Resource' means … actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure." 16 U.S.C. § 839a(19). In addition, conservation is acquired by BPA under section 6. "The Administrator shall acquire such resources through conservation, implement all such conservation measures, and acquire such renewable resources which are installed by a residential or small commercial consumer to reduce load …" 16 U.S.C. § 839d(a)(1). Because conservation is acquired from 7(b)(2) Customers, it is a Type 1 resource. This being the case, section 7(b)(2)(D) requires that any conservation being acquired by BPA must be included in the resource stack as a non-FBS resource and available to meet 7(b)(2) Customer load to the extent it is needed and it is among the least expensive resources available. *See* Issue 3, *supra*.

Section 7(b)(2)(D)(ii) describes the second type of resource as those "not committed to load pursuant to section 5(b)." These are resources owned or purchased by the 7(b)(2) Customers that are not dedicated to load. Section 5(b)(1) of the Northwest Power Act provides:

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds – (A) the capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and (B) such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region.

16 U.S.C. § 839c(b)(1). As noted in section 3(19) of the Northwest Power Act, the term "resource" includes "electric power." 16 U.S.C. § 839a(19). Because section 5(b) applies to requirements determinations for both preference customers and investor-owned utilities, section 7(b)(2)(D)(ii) precludes BPA from including resources owned or purchased by 7(b)(2) Customers in the 7(b)(2) Case resource stack if such resources are committed to load by preference customers or investor-owned utilities.

Together, sections 7(b)(2)(D)(i) and (ii) result in a list of resources which are assumed to be available to meet 7(b)(2) Customer loads. The remainder of section 7(b)(2)(D) outlines how this list of resources is to be used to serve the 7(b)(2) Customers' loads and describes the third type of resources available to meet 7(b)(2) Case loads. BPA is to assume for the 7(b)(2) Case that any required additional resources "were the least expensive resources owned or purchased by public bodies or cooperatives." This means that 7(b)(2)(D)(i) and (ii) resources are stacked in order of cost and pulled from that stack to meet 7(b)(2) Customers' loads in order of least to greatest cost. Should these resources be insufficient to satisfy the General Requirements of 7(b)(2) Customers, section 7(b)(2)(D) provides the assumption that "... any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator." This third resource type consists of the other new resources acquired by BPA in an amount required to meet the 7(b)(2) Customers' remaining loads, the cost of which is determined by the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the relevant Five-Year Period.

12. Interpretation: Section 7(b)(2)(E) requires an assessment of the Quantifiable Monetary Savings that are realized by public body financing of resources that are in the resource stack.

Discussion:

Section 7(b)(2)(E) states that the Administrator is to assume that "the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, … were not achieved." 16 U.S.C. § 839e(b)(2)(E). The legislative history adds some clarification to this language. "The cost of resources to meet these requirements are … (b) Costs of new resources, either actual or hypothetical, constructed or acquired by the public bodies and cooperatives as necessary to meet these preference customer load requirements using the financing costs of such agencies that would have resulted if actions of the Administrator under Section 6 of the Bill were not achieved." S. Rep. No. 272, 96th Cong., 1st Sess., 58 (1979), Appendix B.

This subsection provides that the 7(b)(2) Case is to assume that the cost of resources in the subsection 7(b)(2)(D) resource stack is to exclude any 7(b)(2) Customer's financing benefits due to BPA's purchase of the output of the resource.

13. Interpretation: Section 7(b)(2)(E) requires an assessment of the value of Reserve Benefits acquired by BPA due to the Northwest Power Act.

Discussion:

Section 7(b)(2)(E) states that the Administrator is to assume that "the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from … reserve benefits as a result of the Administrator's actions under this chapter were not achieved." 16 U.S.C. § 839e(b)(2)(E). Reserve Benefits result from resources designated by BPA to provide reserves and BPA's restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these resources and restriction rights may be unavailable to BPA. Without the restriction rights, for example, BPA would have to incur the costs of providing an equivalent amount of reserves from another source. This subsection provides that the 7(b)(2) Case is to assume that cost reductions attributable to Reserve Benefits are not achieved in the 7(b)(2) Case. Therefore, the 7(b)(2) Case revenue requirement is to assume the extra cost of procuring the reserves provided to the Program Case.

Attachment B

Implementation Methodology of Section 7(b)(2) of the
Pacific Northwest Power Planning and Conservation Act

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SECTION 7(b)(2) OF THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT

IMPLEMENTATION METHODOLOGY

September 2008

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DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

Implementation Methodology of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act

I. Introduction

The Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act"), 16 U.S.C. § 839, confirms BPA's obligation to establish and revise BPA's rates for the sale and transmission of electric power. Section 7(b)(2) of the Northwest Power Act provides that:

> after July 1, 1985, the projected amounts to be charged for firm power for the general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if the Administrator …

makes a set of assumptions, outlined in the remainder of section 7(b)(2). These assumptions hypothetically remove the effects of certain provisions in the Northwest Power Act. In order to implement the provisions in section 7(b)(2), BPA has formulated a methodology that specifies how BPA will conduct the section 7(b)(2) rate test.

The implementation of section 7(b)(2) in any given BPA rate proceeding requires two distinct steps. The first step is to compare a set of annual rates developed under all the provisions of the Northwest Power Act before considering the effects of section 7(b)(2) (the Program Case), with a set of annual rates developed under the assumptions outlined in section 7(b)(2) (the 7(b)(2) Case). Both sets of rates are those applicable to public body, cooperative, and Federal agency customers (7(b)(2) Customers) and are based on the costs of power required to serve the General Requirements of those customers over the Five-Year Period.

If the rates in the Program Case are determined to be higher than those in the 7(b)(2) Case, then rate protection is to be afforded to preference customers and a second step is required. The allocated costs of the 7(b)(2) Customers must be reduced by the amount of rate protection afforded by the rate test and the difference allocated to other BPA rates pursuant to section 7(b)(3) of the Northwest Power Act. This potential reallocation must be made within the framework of sound ratemaking principles and BPA's statutory obligations.

II. Definitions

This section contains definitions applicable to section 7(b)(2). Terms identified in the Northwest Power Act have the same meaning in this section, unless further defined.

1. Relevant Rate Case: The section 7(i) wholesale power rate adjustment proceeding being conducted at the time the projections for section 7(b)(2) are made, and in which any adjustment to rates in accordance with section 7(b)(2) may be reflected.

2. General Requirements: The public body, cooperative, and Federal agency customers' electric power assumed in the Relevant Rate Case to be purchased from BPA, exclusive of new large single loads. General Requirements are limited to power purchased from BPA under section 5(b) of the Northwest Power Act; section 5(c) purchases from BPA are not included.

3. 7(b)(2) Customers: Those firm power customers of BPA that are listed in section 7(b)(2) of the Northwest Power Act as subject to the rate test, *viz.*, public bodies, cooperatives, and Federal agencies.

4. Applicable 7(g) Costs: The costs identified in section 7(g) of the Northwest Power Act that are also listed in section 7(b)(2), *viz.*, costs chargeable to 7(b)(2) Customers for conservation, resource and conservation credits, Experimental Resources, and Uncontrollable Events.

5. Uncontrollable Event: A discrete event which differs from the continuum of changing events that occur in nature, business, and government (such as changes in water conditions, aluminum prices, and electricity markets) and that are routinely reflected in ratemaking.

6. Experimental Resources: Resources that are undergoing research and development and are funded by BPA in full or in part.

7. Five-Year Period: The rate recovery period of the Relevant Rate Case, plus the ensuing four years. If the Relevant Rate Case has more than a one-year rate recovery period, the Five-Year Period will be greater than five years.

8. Program Case: The entire process of calculating rates to be charged in the Five-Year Period of the Relevant Rate Case under the provisions of the Northwest Power Act other than section 7(b)(2), including all specific data, assumptions, and results.

9. 7(b)(2) Case: The entire process of calculating rates for the relevant Five-Year Period under the provisions of section 7(b)(2) of the Northwest Power Act, including all specific data, assumptions, and results.

10. Five Assumptions: The five differences between the Program Case and the 7(b)(2) Case specified in subsections (A) through (E) of section 7(b)(2) of the Northwest Power Act.

11. DSI Loads: Those loads of direct service industries (DSIs) that are forecast to be served by BPA, during the Five-Year Period, pursuant to section 5(d)(1) or 5(f) of the Northwest Power Act.

12. Within or Adjacent: Relating to DSI customer loads determined in accordance with section 7(b)(2)(A) to be electrically within or adjacent to the geographic service territories of 7(b)(2) Customers.

13. Quantifiable Monetary Savings: The change in annual costs attributable to differences in resource financing or Reserve Benefits.

14. Reserve Benefits: The annual financial value of (1) resources designated by BPA as providing reserves, or (2) interruptible load that forestalls a resource acquisition by virtue of the ability to curtail the load at a time when off-line generation would otherwise need to be available to start up and serve load during unexpected conditions.

III. Legal Interpretation

BPA first published a Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act in 1984. 49 Fed. Reg. 23,998 (June 8, 1984). The first Legal Interpretation presented BPA's interpretation of section 7(b)(2) of the Northwest Power Act, incorporating principles of statutory construction and a review of legislative history. In addition, BPA considered the views expressed in a series of informal meetings with interested persons and in comments received in response to the publication of an earlier notice of a draft Legal Interpretation. The scope of the notice was limited to those issues that relied on statutory language or legislative intent for resolution.

Concurrent with the consideration of this revision to the Implementation Methodology, BPA is proposing revisions to the Legal Interpretation. This Methodology incorporates changes to conform to revisions to the Legal Interpretation.

Briefly, BPA interprets section 7(b)(2) as follows:

1. Section 7(b)(2) limits the 7(b)(2) Case to the Five Assumptions listed in section 7(b)(2) and the secondary effects of those assumptions.

2. Implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a).

3. Applicable 7(g) Costs are to be excluded from the Program Case revenue requirements and the 7(b)(2) Case revenue requirements prior to further determination of the 7(b)(2) Case power costs.

4. The appropriate Five-Year Period is the rate recovery period for the applicable rate case plus the ensuing four years.

5. 7(b)(2) Customers' loads include DSI Loads that are Within or Adjacent to the 7(b)(2) Customers' service territories.

6. BPA will use Appendix B of the Senate Report to assist in determining which DSI Loads are Within or Adjacent to the geographic service boundaries of 7(b)(2) Customers.

7. All DSI Loads assumed to be placed on 7(b)(2) Customers will be treated as firm loads.

8. Section 7(b)(2)(B) necessitates an examination of Program Case contracts in the determination of "Federal base system resources not obligated to other entities."

9. Section 7(b)(2)(B) requires the allocation of resource pools to load pools in the Program Case to be reconsidered in the 7(b)(2) Case.

10. Section 7(b)(2)(C) requires the exclusion of all costs relating to the section 5(c) exchange, otherwise known as the Residential Exchange Program, from the 7(b)(2) Case. In addition, the loads and resources associated with the exchange will also be excluded from the 7(b)(2) Case.

11. Section 7(b)(2)(D) identifies three additional resource types assumed to be available to meet the 7(b)(2) Customers' remaining General Requirements when FBS resources are exhausted. Type 1 are those resources not included in the FBS that are actually acquired by BPA from 7(b)(2) Customers in the Program Case. Conservation is a Type 1 resource. Type 2 are those resources owned or purchased by the 7(b)(2) Customers and not dedicated to load by public agencies or investor-owned utilities pursuant to section 5(b). These two types of resources are to be stacked in order of cost and then pulled from the stack to meet 7(b)(2) Customers' loads as needed, least expensive first. Type 3 resources are additional acquired resources not included in the FBS, which are priced at the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the Five-Year Period.

12. Section 7(b)(2)(E) requires an assessment of the Quantifiable Monetary Savings that are realized by public body financing of resources that are in the resource stack.

13. Section 7(b)(2)(E) requires an assessment of the value of Reserve Benefits acquired by BPA due to the Northwest Power Act.

IV. The Program Case

In performing the 7(b)(2) rate test, the Program Case is the Five-Year Period projection of the average annual power rates for serving the General Requirements of the 7(b)(2) Customers conforming with all the provisions of the Northwest Power Act before considering the effects of section 7(b)(2). All rate proposal determinations, decisions, and assumptions for the rate recovery period regarding revenue requirements, loads, resources, cost allocation, and rate design will be used. All data for the ensuing four years will be consistent with or extrapolated from rate recovery period data. Ratemaking methodologies, such as those based on the rate directives in the Northwest Power Act and those used to allocate costs and revenue adjustments to BPA customer classes, will be unchanged over the Five-Year Period.

If BPA uses its section 7(e) rate design discretion to implement an alternative tiered rate form, that rate design flexibility will be applied subsequent to the section 7(b)(2) rate test. In such cases, the rate test will continue to be performed with all cost allocated to, and all loads included in, the 7(b) load pool, without respect to the tiering of such costs and loads.

1. Load Forecast

A load forecast will be developed for every BPA rate proposal independent of any requirements for implementing section 7(b)(2). It will include estimates of BPA programmatic conservation savings for the forecast period. The treatment of power sales contracts that expire during the Five-Year Period will be the subject of each Relevant Rate Case. This forecast will provide the load estimates for the Program Case.

2. DSI Loads

A load forecast of purchases by DSIs from BPA will be developed for the Five-Year Period. This forecast, without consideration of the rate schedule under which the power is sold, will define the DSI Loads for the Program Case.

3. Resources

Regional resource generation studies are also conducted for BPA's rate proposals. These studies determine the capability of BPA's and the region's hydro and thermal resources for the Five-Year Period. The resource study results will be consistently applied through the Five-Year Period except as modified to reflect the start of commercial operation or retirement of generating resources and also for the planned effect or expiration of relevant contracts or purchases. Firm and secondary hydroelectric generation will be based on these studies. Assumptions about the level of surplus firm power sales for the Program Case will be the same as those made for the Relevant Rate Case.

4. Revenue Requirements, Including Residential Exchange Costs

BPA's repayment process will be used for the determination of BPA revenue requirements through the Five-Year Period. Costs will be projected over the Five-Year Period using budget estimates, when available. Estimates of future inflation and real cost escalation and planned additions to BPA's power system will be used when budget estimates are unavailable.

5. Surplus Firm and Secondary Sales

The Program Case establishes the forecast of revenues from surplus power sales, whether the surplus is firm or secondary.

6. Subtracting Applicable 7(g) Costs

Prior to comparing the Program Case rates to the 7(b)(2) Case rates, section 7(b)(2) directs that the Applicable 7(g) Costs are to be subtracted from the Program Case rate. To accomplish this, the amounts of Applicable 7(g) Costs allocated to the 7(b) rate pool will be removed from the Program Case rates. To do so, the allocated Applicable 7(g) Costs will be expressed as a unit rate comparable to the 7(b) rate and will be subtracted from the annual 7(b) rates to calculate the adjusted Program Case rates.

7. Summary Methodology for the Program Case

The procedures and data from the rate proposal cannot be described in detail in this document. They are properly rate case determinations that are outside the scope of the Methodology for implementing section 7(b)(2). The Section 7(b)(2) Methodology must be flexible enough to incorporate the procedures and data from the rate proposal for which the section 7(b)(2) rate test is being conducted. These procedures and data, as part of a BPA rate filing, are in turn subject to review and comment pursuant to section 7(i) of the Northwest Power Act. The Section 7(b)(2) Methodology can require only that the rate proposal procedures and data be modeled or incorporated as accurately as possible, which will be subject to examination during the Relevant Rate Case.

In summary, the Program Case will be BPA's best projection of its rates without considering the effects of section 7(b)(2). The exact procedures for the rate calculation in the Program Case cannot be determined until BPA has prepared its rate proposal. However, the rate test modeling will reflect the rate proposal procedures as completely as possible in producing the Program Case when the rate test is conducted for that rate proposal.

V. The 7(b)(2) Case

The language of section 7(b)(2) not only directs BPA to conduct a rate test for the 7(b)(2) Customers, but also provides a considerable amount of direction as to how the rate test is to be conducted. BPA's Legal Interpretation provides the general approach to developing the 7(b)(2) Case. Based on this, the 7(b)(2) Case will be modeled in the same way as the Program Case, except where section 7(b)(2) provides specific assumptions that modify the Program Case. The modeling of these Five Assumptions and their secondary effects may lead to different results than the underlying premises and ratemaking processes that will be held constant between the two cases. The remainder of this section outlines how the 7(b)(2) Case rate calculations for the Five-Year Period will be developed.

1. Load Forecast

The initial loads that will be used in the 7(b)(2) Case will be the same General Requirements as those used in the Program Case, except that they will not include estimates of programmatic conservation savings being acquired by BPA because conservation is a non-FBS resource. In addition, conservation is a resource acquired by the Administrator pursuant to section 6 and, therefore, conservation resources are required to be included in the 7(b)(2) Case resource stack. Because conservation resources must be included in the resource stack to be drawn to meet remaining loads if needed, they have not already been acquired, and therefore they cannot have reduced the loads of the 7(b)(2) Case. To remove the effects of the acquisition of conservation, the 7(b)(2) Customer loads will be increased by conservation being acquired by BPA. Power sales contracts that expire during the Five-Year Period, except for requirements and DSI contracts, will be recognized as expiring as scheduled. This forecast will provide the load estimates for the 7(b)(2) Case.

2. DSI Loads

DSI Loads will be examined on a plant-by-plant basis to reflect whether or not they are Within or Adjacent. All Within or Adjacent DSI Loads will be included in the General Requirements of the 7(b)(2) Customers during the Five-Year Period. DSI Loads not Within or Adjacent are assumed to be served by private utilities. The forecast operating levels of the DSIs that are transferred to public and private utilities are assumed to be served as 100 percent firm loads.

3. Resources

Section 7(b)(2)(B) requires the Administrator to assume that public body, cooperative, and Federal agency customers are served first with FBS resources, and 7(b)(2)(D) requires that additional resources be assumed to serve the remaining general requirements of the 7(b)(2) Customers. As in the Program Case, the FBS in the 7(b)(2) Case will be reduced by any contractual, statutory, or treaty obligations on these resources that were in existence prior to passage of the Northwest Power Act (statutory and treaty including the Canadian Entitlement return, the Hungry Horse Reservation, and Bureau pumping power).

Any contract that BPA enters into subsequent to December 5, 1980, that exchanges FBS capacity for energy, exchanges seasonal FBS energy, or for the sale of FBS capacity with the return of the energy, will be assumed only if there is FBS surplus to 7(b)(2) Customer needs. Therefore, the energy and revenue from such contracts will not be recognized in the 7(b)(2) Case unless there is an FBS surplus in the 7(b)(2) Case. If the FBS surplus does not allow full recognition of these contracts, then a *pro rata* share of energy and revenues will be recognized in the 7(b)(2) Case.

Any surplus FBS resources remaining after meeting FBS obligations, 7(b)(2) Customer loads, and contracts subsequent to December 5, 1980, will be assumed to be sold in the wholesale energy markets at the forecast price assumed in the Program Case for such sales.

If FBS resources, after meeting obligations, are insufficient to meet the loads of the 7(b)(2) Customers, then three types of additional resources can be added to serve those loads. These additional resources are defined in section 7(b)(2)(D) and are: (a) actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case, including conservation resources; (b) existing 7(b)(2) Customer resources not currently dedicated to regional load by preference customers or IOUs; and (c) all other needed resources, acquired at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case. The Type 1 and Type 2 resources will be assumed to come online to meet the remaining General Requirements of the 7(b)(2) Customers after FBS service in order of least-cost first. The resources will then be brought online in the exact amount required to meet the 7(b)(2) Customers' remaining General Requirements. However, once brought online, the resources will remain online throughout the Five-Year Period, even if loads are lower in subsequent years. In such cases, the excess resources will be assumed to be sold at the average cost of all the excess resources and the revenues credited to the 7(b)(2) Case rates.

4. Revenue Requirement

Except for specific exclusions resulting from the Five Assumptions and their secondary effects, the revenue requirement for the 7(b)(2) Case will be the same as the Program Case. The specific exceptions are:

(1) all costs related to the Residential Exchange Program will be removed, including the identified BPA costs of implementing the program. Any costs included in the Program Case that are the result of a settlement of Residential Exchange Program claims will also be excluded;

(2) all costs of any acquisition of new resources will be removed;

(3) Applicable 7(g) Costs will be removed; that is, the costs of conservation, billing credits, experimental resources, and uncontrollable events.

In addition to these explicit exclusions, the secondary effects of their exclusion will be considered. Specifically, for example, the Program Case repayment study will be performed without the excluded costs to determine the interest and amortization applicable to the 7(b)(2) Case.

5. Surplus Firm and Secondary Sales

The load and resource situation in the 7(b)(2) Case may be considerably different from that in the Program Case. The increase in the region's firm load due to the 100 percent firm service to Within or Adjacent DSI Loads, a different load forecast for the 7(b)(2) Case due to conservation removal, and a potentially different set of resources all imply that a different level of surplus firm power may be projected for the 7(b)(2) Case than for the Program Case. The level of surplus firm sales in the 7(b)(2) Case will be determined in the same manner as it is in the Program Case. However, any sales of surplus firm power projected to be made in the Program Case to serve interruptible DSI Loads will not be made in the 7(b)(2) Case. Any firm surplus FBS in the 7(b)(2) Case will be assumed to be sold at the average rate of post-Act contract sales in the Program Case. Any difference between costs allocated to surplus firm and revenues from the sale will be allocated to 7(b)(2) Customers.

Secondary energy generation of the region's hydroelectric system will also be assumed to be the same as in the Program Case. However, the secondary energy sales will be increased in the 7(b)(2) Case to reflect additional sales due to the removal of interruptible DSI Load.

6. Financing Benefits

Section 7(b)(2)(E)(1) requires that BPA assume that Quantifiable Monetary Savings to 7(b)(2) Customers resulting from reduced public utility financing costs for the first two types of non-FBS resources described above were not achieved in the 7(b)(2) Case. Therefore, any additional resources required to serve the General Requirements of 7(b)(2) Customers will not reflect the financing cost reductions implicit in resource acquisitions by public bodies.

A list of eligible resources will be developed, containing cost and sponsor information for each resource. For those resources actually acquired by BPA in the Program Case, and for those resources not dedicated to load and assumed available to BPA, BPA will estimate the financing costs for the resource sponsor assuming that BPA had not acquired the resource output. Finally, when detailed financing cost and sponsor information is not available for planned 7(b)(2) Customer resources, BPA will follow the same procedures, assuming projected public sponsored resource costs. Any changes in financing costs determined from this analysis will be included in the costs of the resources in the 7(b)(2) Case.

For conservation resources acquired by BPA, the financing benefits may include an increased amount of debt financing compared to the Program Case. The amount of debt financing assumed in the 7(b)(2) Case will be determined in the Relevant Rate Case.

7. Reserve Benefits

Section 7(b)(2)(E)(ii) requires BPA to assume that the Quantifiable Monetary Savings resulting from Reserve Benefits were not achieved. Reserve Benefits result from BPA's designated resources or restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these resources and restriction rights may be unavailable to BPA. Without the restriction rights, for example, BPA would incur the costs of providing an equivalent amount of reserves from another source. Therefore, it will be assumed that BPA will incur a level of costs for the benefit of public utilities based on the value of the reserves provided by the designated resources or restriction rights to the Program Case as determined in BPA's rate proposal. The value of reserves determination is currently based, in large part, on the cost of an alternative reserve resource. Also, if the level of reserves provided by the resources or restriction rights is insufficient in the 7(b)(2) Case, based on BPA planning criteria, then additional reserve resource costs will be added in the 7(b)(2) Case.

VI. Rate Test Computer Model

Conducting the section 7(b)(2) rate test requires the use of a computer model to develop the rate projections for the Program Case and the 7(b)(2) Case. The exact form of the Program Case procedures cannot be determined until the time of the Relevant Rate Case for which the rate test is being conducted. The 7(b)(2) Case is inextricably linked to the Program Case as a result of the general approach applied to modeling the 7(b)(2) Case. Therefore, to the maximum extent possible, the exact structure and form of the computer model should be the same as used in determining BPA's actual power rates.

VII. Comparison of Rates

For each of the two Cases, the Program and the 7(b)(2), the rate test model will produce a set of annual average energy rates for the Five-Year Period. These two sets of rates will be used to determine if a reallocation of costs pursuant to section 7(b)(3) is required. The relevant rates for the comparison from the Program Case are BPA's average annual 7(b) rate less Applicable 7(g) Costs. The relevant rates from the 7(b)(2) Case are the per-kilowatthour power costs of serving the General Requirements of the 7(b)(2) Customers.

The 7(b) rate in the Program Case will be developed in the same manner as it is in BPA's rate proposal. The 7(b)(2) rate in the 7(b)(2) Case will include the costs of resources required to serve the 7(b)(2) Customers, along with all other costs and revenue adjustments not excluded by the Five Assumptions and their secondary effects. These costs and revenue adjustments include, but are not limited to, BPA's administrative and general costs, the FBS allocation of contract revenue deficiencies, and secondary revenue credits.

Prior to comparison with the 7(b)(2) rates from the 7(b)(2) Case, the 7(b) rates from the Program Case will be reduced by the Applicable 7(g) Costs listed in section 7(b)(2). All the costs of BPA conservation programs, billing credits, Experimental Resources, and Uncontrollable Events that were allocated to the 7(b) rates will be subtracted. The reduced Program Case rates will then be compared to the 7(b)(2) rates to determine if the 7(b)(2) rates are lower, on average, than the Program Case rates.

The comparison between the Program Case and the 7(b)(2) Case rates will be conducted for the Five-Year Period and will consider the time value of money. Therefore, the two sets of rates will be discounted back to the beginning of the first year of the Relevant Rate Case at BPA's projected future nominal borrowing rate, and then a simple average will be computed over the Five-Year Period. The discounted average rates will be rounded to the nearest tenth of a mill per kilowatthour. If the simple average of discounted 7(b)(2) Case rates is less than that of the Program Case rates, then a determination of an amount of rate protection to be reallocated in BPA's rate proposal is required.

VIII. Determination of Rate Protection Amount

If it is determined that the results of the rate test require a reallocation of costs for BPA's rate proposal to effect the rate protection, then the amount to be credited to the 7(b)(2) Customers and reallocated to BPA's other non-PF Preference sales must be calculated. This credit reflects the fact that it is a rate period adjustment that is based on a Five-Year Period determination. The difference in average discounted rates will be multiplied by the preference customer loads for the Relevant Rate Case to determine the reduction in the 7(b)(2) Customers' rate period costs.

IX. Conclusion

The section 7(b)(2) rate test, up to and including the point at which the rate protection amount is determined, is conducted outside of the mainstream of BPA’s rate development process. Although the rate test reflects the Five Assumptions and their secondary effects used in the rate proposal, the rate test has no impact on BPA rates until the rate protection amount is included in BPA’s rate design. At this point, any adjustment made to reflect the rate test results in BPA rates must be done within the overall framework of the rate development process and of BPA’s ratemaking objectives and statutory requirements. Therefore, the section 7(b)(2) rate test results will be included as a step in BPA’s rate design process, consistent with other statutory provisions and BPA’s ratemaking objectives.

FINAL REPORT

TO

BONNEVILLE POWER ADMINISTRATION

ON

ESTIMATED FINANCING COSTS

FOR
2007 SUPPLEMENTAL POWER RATE CASE
SECTION 7(b)(2) RATE TEST

August 21, 2008

PREPARED BY

PUBLIC FINANCIAL MANAGEMENT

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APPENDIX A TO:

7(b)(2) RATE TEST STUDY, WP-07-FS-BPA-14

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SECTION 1
PURPOSE OF REPORT

The purpose of this report is to provide our recommended financing costs that will be used by Bonneville Power Administration ("BPA") as inputs in their calculation of the "reduced public body and cooperative financing costs" as described in Section 7(b)(2)(E) of the Northwest Power Act. We also discuss certain assumptions and rational used in arriving at these recommended financing costs. In providing the enclosed summary of our conclusions and assumptions, we have relied upon our professional experience and expertise in matters concerning the overall credit markets, the activities of BPA, and other public and private utilities in the Pacific Northwest ("PNW") and throughout the country.

SECTION 2
INTRODUCTION

The Northwest Power Act requires that the Administrator of BPA periodically review and revise the rates for the sale of Federal power and for the transmission of non-Federal power. As part of the process of reviewing and revising the rates for firm power to be charged its preference, Direct Service Industry ("DSI"), Investor Owned Utility ("IOU"), and other customers, the Administrator must follow the requirements of Section 7(b)(2) of the Northwest Power Act. Section 7(b)(2)(E) requires that the Administrator assume that:

> "the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal Base System resources, identified under subparagraph (D) of this paragraph, and reserve benefits as a result of the Administrator's actions under this chapter were not achieved."

Section 7(b)(2)(D) specifies the assumptions to be made to meet public body, cooperative, and Federal agency customer (7(b)(2) Customers) loads. After meeting contractual obligations with Federal Base System ("FBS") resources, additional resources can be added to meet loads of the 7(b)(2) Customers. These additional resources can include: actual and planned resources acquired from 7(b)(2) Customers including conservation programs undertaken or acquired by BPA; existing 7(b)(2) Customer resources not dedicated to regional loads; and generic resources acquired from non-7(b)(2) Customers.

The quantifiable monetary savings associated with the "reserve benefits" per Section 7(b)(2)(E)(ii) relates to reserves that could be made available to BPA by the nature of BPA's contracts with DSI customers. Prior DSI contracts had provided the Federal Columbia River Power System (FCRPS) with reserves through BPA's ability to restrict or interrupt portions of the DSI loads. In prior 7(b)(2) rate cases, the DSI loads were assumed to be served by utilities in the Northwest instead of by BPA. The 7(b)(2) rate test also requires the assumption that these utilities would have had to provide their own reserve resources, and that the utilities would finance reserve resources without BPA participation. BPA's analysis of the restriction rights value in its 7(b)(2) rate cases had contained the assumption that the financing costs associated with such reserves would be different were they acquired by regional utilities.

Similar to BPA's 2002 and 2007 Power Rate Cases, BPA's Power Business Line is forecasting a zero purchase of supplemental reserves from the DSIs for FY 2009 in the 2007 Supplemental Power Rate Case. Therefore, the 7(b)(2) Financing Cost Study will not include resource acquisitions by the Joint Operating Agency (JOA) for the replacement of supplemental reserves provided by the DSIs.

This report provides our conclusions concerning financing costs for BPA's public body, cooperative and Federal agency customers to be used in the 7(b)(2) rate case proscribed in the Northwest Power Act. The conclusions presented in this report represent our opinions as financial advisors familiar with the municipal and governmental utility credit markets and with bond issues for both public power agencies and IOUs in the Pacific Northwest. Given the assumptions noted in this report, our conclusions represent the most probable situation, had the hypothetical situation described in the Northwest Power Act occurred.

SECTION 3
EXECUTIVE SUMMARY

This report derives and provides estimates of the interest rates and differentials associated with financing for the different classes of resources identified in Section 7(b)(2) of the Northwest Power Act. Prior 7(b)(2) rate cases have utilized both historic and projected interest rate assumptions for several financing structures. Historic interest rate assumptions have been applied to the financing of prior expenditures for “Named Resources”, conservation resources and other forms of generation resources. Projected interest rate assumptions have been applied to the financing of prospective expenditures for potential conservation and generation resources. This report also derives and provides estimates of interest rates and differentials associated with the different classes of resources in the Program Case. In the case of certain

Named Resources, actual historical financing costs were utilized. Table A contains a summary of historical and projected interest rate assumptions for various resource categories. It is important to note that Table A has been developed from the format provided in prior 7(b)(2) rate study analyses. The prior studies sought to provide historical and prospective interest rates for long-term, fixed-rate financings. As such, the rates provided in the prior studies were for level debt service financing structures with an assumed final maturity of roughly 30 years. In order to estimate the average interest rate for a 30-year financing, prior studies used various interest rate measures for bonds having a term of 25 years. We concur that the selection of interest rate indices having a 25-year term represents a reasonable estimate of the financing costs for 30-year, level debt service borrowings.

TABLE A – Summary of Historical and Projected Interest Rate Assumptions

Resource	Program Case Interest Rate With BPA Backing	7(b)(2) Case Interest Rate Without BPA Backing	Interest Rate Differential Basis Points
Historical Named			
Idaho Falls	Not Applicable	Not Applicable	Not Applicable
Cowlitz Falls (25Yr)	4.20% Actual (1)	4.25%	5
Projected Conservation (2)			
BPA Sponsored (25 Yr) Table C, page 14	4.51%	4.73%	22
BPA Sponsored (20 Yr) Table D, page 15	4.46%	4.68%	22
BPA Sponsored (15 Yr) Table E, page 15	4.33%	4.53%	20
BPA Sponsored (10 Yr) Table F, page 16	4.01%	4.20%	19
BPA Sponsored (5 Yr) Table G, page 16, see note 3.	3.58%	3.79%	21
Projected Generation			
Public (25 Yr) Table C, page 14	4.51%	4.73%	22
Non-7(b)(2) (25 Yr) Table I, page 19	5.89%	4.73%	-116

(1) Actual True Interest Cost of refunding issue sold August 24, 2003.

(2) The interest rates provided for various Projected Conservation categories are assumed for either BPA or JOA borrowings having the maturities so listed. In the 2007 Supplemental Power Rate Case Section 7(b)(2) Study, BPA assumes that conservation measures related to 2001 and prior had a useful life of 20-years, and for years 2002 and after that a useful life of 15-years applies. Those expenditures are assumed to be financed by the JOA over a useful life of 20 and 15 years, depending on the vintage year of the investment. During FYs 2000-2007, BPA issued $142 million in conservation bonds with 3 or 4 year terms. The weighted average term was 3.21 years, with a weighted average interest rate of 4.71%.

(3) During the 2007 Supplemental Power Rate Case study period FY 2009 – FY 2013, BPA projects that it will borrow $192 million for conservation investments using five-year maturities with a weighted average interest rate of 5.90%. The bonds will be issued through the U.S. Treasury so they are not comparable to the tax exempt rates included in the table.

In Table A, we have again provided interest rate assumptions based on indices and market data for 25-year maturities, along with assumptions for 5-year, 10-year, 15-year and 20-year maturities to finance conservation investments. (See Table C through G further in this report.)

The Program Case Interest Rates and 7(b)(2) Case Interest Rates shown in Table A above are derived from historic borrowing cost and interest rate information compiled for the purposes of the Section 7(b)(2) rate test. The historic interest rate differentials are a reasonable basis for establishing assumptions for projected interest rate differentials for borrowing costs for the period encompassing BPA's 2007 Supplemental Power Rate Case. It is important to note that the interest rate assumptions in Table A for Projected Conservation and Projected Generation expenditure are derived from historical interest rate average over the past three years. In prior 7(b)(2) Rate Test Studies, the interest rate assumptions were developed by averaging data over a ten year period preceding the relevant 7(b)(2) Rate Test Study. As discussed later in this report, the credit markets are undergoing a degree of volatility and uncertainty that has not been experienced in several decades. This period began roughly a year ago, and there is no consensus as to how long it will last or how severe it will be. One clear impact of the current market environment is that interest rate differentials between various credit ratings are more pronounced than it has been over the past 20 years. The impact of recent credit market volatility has not been as pronounced in the governmental market sector examined by this report, as compared to lesser rated credits. However, these market sectors – mid-to-high investment grade, tax-exempt, municipal utility bonds – have seen some degree of increased interest rate spreads between rating categories.

Given that:
1 - an important product of this report is the assumed interest rate differential between the Program Case Interest Rates and the 7(b)(2) Case Interest Rates,
2 – the interest rate differential between the two cases is derived entirely by exploring interest rate data for various credit rating categories, and
3 – that current, and perhaps future market conditions are markedly different from conditions over the past ten years;

PFM is of the opinion that it would be inappropriate to develop assumptions for the upcoming rate test period by utilizing the past practice of averaging data from the prior ten year period. Therefore, PFM recommends revising the prior Rate Test Study practice of using the most recent ten years of interest rate data, and instead utilizing the most recent three years of data as a reasonable assumption for the purpose of the current Rate Test Study. While future market conditions remain uncertain, PFM is of the opinion that utilizing the recent three year period will reflect that likelihood that some degree of market disruption is likely to persist for at least a portion of the period covered by the current Rate Test Study.

A general observation from the data provided in Table A is, that for most financing categories, the 7(b)(2) Case interest rates are higher than those assumed in the Program Case. When there is a positive number in the “Interest Rate Differential” column, it represents that amount by which the 7(b)(2) Case interest rate is higher (or more costly) than the Program Case.

The interest rate averages listed above in Table A would serve as the assumed interest rates for the Program Case and 7(b)(2) Case for the prospective maturity terms outlined.

SECTION 4
ASSUMPTIONS

In developing our interest rate assumptions, we have used the types of financing that most likely would be, or could have been, used at the time of funding the hypothetical resources acquired according to the terms of the 7(b)(2) rate test. We have relied upon common and accepted legal and financing structures for the hypothetical public financing entity that the 7(b)(2) Customers are assumed to have formed. Similarly, discrete borrowings undertaken by 7(b)(2) Customers and non-7(b)(2) Customers, would be assumed to be financed using customary public financing methods for long-term, fixed-rate financing. Such assumptions as to legal and financing structure represent, in our opinion, the most prevalent means for financing large-scale resource acquisition programs similar to what BPA or its customers could have undertaken or would utilize in the future.

As noted above, the Northwest Power Act requires that an estimate be provided of the financing costs to customers in the 7(b)(2) Case because the customers themselves would have to finance the acquisition of additional resources needed to meet their firm loads after BPA's FBS resources are exhausted. An assumption has been made in prior 7(b)(2) Financing Cost

Studies, with which we concur, that the 7(b)(2) Customers would have formed a Joint Operating Agency ("JOA") where the financing would have been the responsibility of the participant agencies in the financing. This would have been a similar, but not identical, legal structure to Energy Northwest and other JOAs such that underlying legal obligations would have been clearly enforceable.

The member agencies of the JOA are listed in Attachment A along with their respective shares and credit ratings. All of the member agencies are assumed to have signed "take-or-pay agreements," such that each would pay for its proportionate share of the debt service on the financing regardless of whether or not the project produced the expected levels of output. In the event that one participant failed to pay its share of debt service, each remaining participant would be responsible for an increased level of debt service of up to 125 percent of the member agency's original commitment. Based on such a typical JOA financing structure, and in concurrence with the assumptions contained in prior 7(b)(2) Financing Cost Studies, we have assumed that a financing by a JOA consisting of the assumed member agencies would have received and been able to maintain a rating in the "A" category from both Moody's and S&P - two well regarded bond rating agencies. In the case of the JOA or 7(b)(2) Customer issuing revenue bonds with the advantage of a BPA "take-or-pay" or "capability" power sales contract, we have assumed that the financing would have received and maintained a rating in the "Aa/AA" category from both Moody's and S&P.

In estimating the financing costs for specific Named Resources, such as the Cowlitz Falls Project, we have assumed a rating based upon the particular sponsor's credit rating. Therefore, the ability of the Public Utility District No. 1 of Lewis County (Lewis County PUD), for example, to service its own load with the resource is also assumed in order to meet requirements for investment grade ratings from both Moody's and S&P. Similarly, we have estimated financing costs for other anticipated conservation and generation resource providers, assuming that suitable uses for the resource output were available.

SECTION 5
ASSUMPTIONS CONCERNING RESOURCE ACQUISITIONS

In previous rate cases, BPA has assumed the JOA would have undertaken two phases of resource acquisition. The first phase assumed the acquisition of peaking resources to replace the reserve benefits provided by the DSI load that are not provided in the 7(b)(2) Case. Unlike some prior rate cases, BPA's Power Business Line is forecasting a zero purchase of Supplemental Reserves from the DSIs in the 2007 Supplemental Power Rate Case. Therefore, the current 7(b)(2) study will not include resource acquisitions by the JOA for the replacement of supplemental reserves provided by the DSIs.

The second phase of resource acquisition program assumes the acquisition of individual projects involving conservation resource and generation resource programs sponsored by 7(b)(2) Customers as well as a variety of other sponsors. In prior years, BPA has acquired resources through its Competitive Resource Acquisition Program, unsolicited proposals, and BPA Billing Credit programs. In recent years, BPA has acquired wind and solar renewable resources along with small hydro and waste heat recovery resources through direct acquisitions.

The City of Idaho Falls and BPA entered into a replacement Power Purchase Agreement dated September 5, 2006, for the purchase of all power and energy produced from four hydroelectric generating plants operated by the City of Idaho Falls (the Idaho Falls Project). Lewis County PUD entered into a Power Purchase Agreement dated May 23, 1991, with BPA for the output of the Cowlitz Falls Hydroelectric Project (the Cowlitz Falls Project). BPA has solicited for resources through the BPA Billing Credits Policy contained in section 6(h) of the Northwest Power Act and the Competitive Resource Acquisition Program, which includes the Resource Contingency Program. Under the BPA Billing Credits Policy, BPA has contracted for the output of four projects consisting of South Fork Tolt, Wynocchee, Short Mountain Landfill, and Smith Creek. The total output of these four projects totals 20.0 aMW. Under the terms of the BPA Billing Credits Policy, BPA's obligation to purchase the output is subject to the availability of the resource and, therefore, we do not believe the existence of the BPA power purchase agreement to be material to the credit rating of the financing associated with these particular resources.

In general, the hypothetical financing agency consisting of the 7(b)(2) Customers would apportion the risks of resource acquisition due to non-completion, technical difficulties or other factors among the member agencies in proportion to their ownership shares. Similarly, individual resource sponsors are assumed to accept such risks without allocation to third parties. Thus, the risks of non-completion or technical difficulties are not assumed to be factors that would impact the financing costs of particular resources.

We have assumed that all financings will utilize traditional fixed-rate debt with a level debt service structure. The revenue bonds or project financings issued by, or entered into by, 7(b)(2) Customers, non-7(b)(2) Customers or other entities would have comparable features.

Financing of the Cowlitz Falls Project and the Idaho Falls Project is assumed to have occurred at the time when the sponsors of each of the projects issued revenue bonds to provide for the capital costs of each respective resource. Resources to be acquired from non-7(b)(2) Customers are assumed to be acquired on a project finance basis. In the Program Case, BPA would contract to purchase power output. In the 7(b)(2) Case, BPA would contract with the JOA.

In addition, it is assumed that all financings by 7(b)(2) Customers are structured to take full advantage of tax-exempt financing, subject to the provisions of applicable tax law. Also, we would note that section 9(f) of the Northwest Power Act requires certain certifications by the Administrator prior to the acquisition of resources, which must be met in order that the exemption from gross income in section 103 (a)(I) of the Internal Revenue Code of 1986 be achieved. As a result, the assumption is made for the purposes of the resource acquisitions contemplated with BPA, that the tax-exemption for financings will not be adversely affected and that BPA will be able to provide the certifications required under the Northwest Power Act.

We would also note that the assumed credit ratings on revenue bonds involving an obligation of BPA have remained stable in recent years. Uncertain water conditions, the financial requirements of BPA's resource acquisition programs, fish and wildlife issues, and other items are significant issues affecting the PNW and BPA's credit ratings. However, for the purposes of the 7(b)(2) rate case, no change in credit ratings is projected for BPA, or the 7(b)(2) Customers, as it pertains to the financing feasibility of particular resources financed with debt issued in the public credit markets.

SECTION 6
IDAHO FALLS PROJECT

On April 1, 1982, the City of Idaho Falls, Idaho executed a Power Purchase Agreement whereby BPA agreed to a long-term purchase of the output of four hydroelectric generating plants to be constructed in the service territory of the City of Idaho Falls. The City of Idaho Falls provided for the capital costs of constructing the four hydroelectric generating plants with the proceeds of revenue bonds issued in 1981. These bonds were subsequently refinanced on multiple occasions. A new five-year Power Purchase Agreement for the period October 1, 2006 through September 30, 2011 was executed on September 5, 2006. This agreement states that it is the intent of the parties to negotiate a successor contract prior to the expiration of the current contract. Because the revenues of the City's Electric System (as defined) secure the City of Idaho Falls revenue bonds issued to finance the Project, we do not believe the existence of the BPA Power Purchase Agreement to be material to the credit rating of these bonds. Therefore, the cost of the Idaho Falls Project resource would not change as a result of the financing assumptions required by the 7(b)(2) rate case.

SECTION 7

COWLITZ FALLS PROJECT

On May 23, 1991, Lewis County PUD entered into an Amendatory Contract for Power Purchase (the Contract) whereby BPA agreed to enter into a long-term purchase of the output of a hydroelectric generating plant known as the Cowlitz Falls Project (Cowlitz Falls Project). BPA and Lewis County PUD agreed that Lewis County PUD would finance construction of the Project through the issuance of revenue bonds, with BPA agreeing to pay to or on behalf of Lewis County PUD amounts equal to Project Power Costs (as defined) including Annual Debt Service (as defined) on such revenue bonds for the life of the Contract. On August 27, 1991, Lewis County PUD issued $171,095,000 in Public Utility District No.1 of Lewis County, Washington, Cowlitz Falls Hydroelectric Project Revenue Bonds, Series 1991. The bonds were rated Aa/AA with annual debt service payments of approximately $13,465,000 and a final maturity of October 1, 2024. The callable bonds of this series were again refunded on August 23, 1993. The remaining 1991 bonds and the callable bonds issued in 1993 were refunded again on June 19, 2003.

Under the terms of the Contract, the primary source of security for the bonds is revenue received from BPA pursuant to the Contract and a Payment Agreement (the Payment Agreement). Under the Contract, BPA is obligated to pay all project costs, including debt service, whether or not the project is completed or power is delivered. If BPA does not make payment under the Contract, it is obligated to pay debt service under the Payment Agreement directly to the bond trustee. Debt Service on the bonds, along with the payment of operating and maintenance (O&M) expenses of the project, have priority over payments of BPA's Treasury debt and repayment of the Federal investment in the Columbia River Power System.

Because the revenues from the Contract and the Payment Agreement secure Lewis County PUD's revenue bonds issued to finance the Project, we believe that the Contract and Payment Agreement are the primary support for the current credit ratings. BPA retains the "dry hole risk" for the Project and is obligated to pay debt service on the Bonds for their full term whether the Project is operating or not. For the purposes of the 7(b)(2) test, Lewis County PUD is assumed to accept the "dry hole risk" and that the Cowlitz Falls Project output would be dedicated to serving Lewis County PUD's own load.

The original bonds were priced on Tuesday, August 27, 1991, with a True Interest Cost of 7.10%. The refunding Bonds priced on Tuesday, August 23, 1993 had a True Interest Cost of 5.61%. The refunding Bonds priced on June 19, 2003 had a True Interest Cost of 4.20%. Of the $146,210,000 of bonds sold in 2003, $135,930,000 was guaranteed by municipal bond insurance companies and rated AAA. The uninsured bonds maturing in years 2005 through 2007 were rated Aa2/AA-. As stated earlier, we believe that a bond issued on behalf of the 7(b)(2) Customers would have carried a rating in the A category. During the months preceding the Lewis County sale, there were several bond issues sold for A-rated electric utilities. However, in most every case, these bonds were also guaranteed by a municipal bond insurance policy – and rated AAA. Interest rates on these insured bonds were comparable to those of the Lewis County bonds. In our opinion, the net financing cost differential between AA- and A-rated bonds that were both backed by AAA-rated insurance policies would have been a function of the price charged by the insurance companies. In the case of the Lewis County bonds, one insurance policy for a portion of the bonds was priced at .33% of the total amount of insured debt service. The other policy applied to a different grouping of bonds was priced at .475% of insured debt service. The amount of these premiums is taken into account in the calculation of the 4.20% True Interest Cost on the bonds. In our opinion, at the time the Lewis County bond sold, an approximate market insurance premium for an A-rated issuer would have been approximately .75% of insured debt service. A recalculation of the Lewis County True Interest Cost with the .75% assumed insurance premium produces a rate of 4.25%. In our opinion, we believe that the borrowing advantage to the 7(b)(2) Customers from the BPA backing is approximately equal to the 5 basis point differential between the two True Interest Costs.

SECTION 8
JOA BORROWING COSTS

For purposes of establishing assumptions for JOA borrowing costs, we feel it is appropriate to utilize the historical interest rate assumptions from 7(b)(2) Financing Cost Studies conducted prior to the 2007 Power Rate Case ("Pre-2007 Power Rate Studies"). However, as in the Final 2007 Power Rate Study published in July 2006, we feel that there are more appropriate measures for more recent rates and projected interest rate assumptions. For Pre-2007 Power Rate Financing Cost Studies, 7(b)(2) historical assumptions were based upon an analysis of bond issues for selected public power agencies for the period from January 1, 1982 to March 8, 1999. The analysis compared the True Interest Cost for each financing for each FY to the Bond Buyer 25-Bond Revenue Bond Index (Revenue Bond Index). The Revenue Bond Index consisted of revenue bonds maturing in 30 years. At times, roughly 10 of the 25 bonds included in the index are electric power related financings. In general, the Revenue Bond Index consists of issuers with an average rating equivalent to Moody's "A1" and Standard & Poor's "A+" with a concentration of issuers rated "A1/A +" or "AA/Aa" from at least one rating agency.

The Pre-2007 Power Rate Financing Cost Studies then analyzed the relationship between bonds of different rating categories to the Revenue Bond Index. In this portion of the analysis, it was decided to eliminate Energy Northwest from the list of power revenue bond issuers with at least "AA" from either rating agency in order to assess the effect that the sometimes heavy issuance of refunding revenue bonds by Energy Northwest may have had on the Revenue Bond Index and the various rating categories. For each year prior to FY 1996, the study determined the average percentage represented by: (1) the true interest costs of large public power issues in a given year, divided by: (2) the Revenue Bond Index in place on the sale dates. This calculation was performed for bond issues in the A-rated category and bond issues in the AA-rated category – excepting Energy Northwest issues. The annual average of the individual issue percentages in each rating class was then multiplied by the average Revenue Bond Index for the entire fiscal year to arrive at an assumption for the average borrowing costs for A-rated and AA-rated issuers during that year.

The 2002 7(b)(2) Rate Study recognized: (1) the diminishing data set of A-rated public power bonds due to the increasing use of AAA bond insurance, and (2) the existence of useful market indices such as the Bloomberg Capital Markets fair value yield curves. The Bloomberg Capital Markets calculates daily indexes for several rating categories and maturity ranges for power revenue bonds. The information appears to be generally consistent with information included from prior years based upon the actual issuance of power revenue bonds by different rated issuers. The Bloomberg yield curves provide data for electric revenue bonds of several credit rating categories, including bonds rated A-, A+, AA- and AA+. In order to estimate rates for bonds in the A and AA rated categories, we took the average of published rates for the A- and A+ categories for the A-rated data, and took the average of published rates for the AA- and AA+ categories for the AA-rated data. Interest rate estimates are for financings with level debt service and a 30-year final maturity. The Bloomberg rates for 25-year maturities were used as the best estimates of financing costs for this financing structure. These averages for FY 2004 and prior fiscal years are found in Table B. Table B provides the following information:

(1) the annual average of the Revenue Bond Index,
(2) the calculated hypothetical AA-rated (and thus BPA-backed) average financing cost,
(3) the calculated hypothetical A-rated (and thus JOA-backed) average financing cost, and
(4) the interest rate differential between #s (3) and (4) for fiscal years prior to 2004.

For more recent years' interest rate assumptions, and for the 2007 Supplemental Power Rate Case that resets FY 2009 rates, we suggest utilizing a similar methodology for establishing the estimated rates for A and AA rated electric revenue bonds. We again used the database of Bloomberg interest rates for AA-rated and A-rated, 25-year tax-exempt electric revenue bonds as the best proxies for BPA and JOA borrowing costs. However, we suggest a departure from the prior practice of developing the assumptions for financing costs that utilized historical interest rates over the most recent ten years. As discussed on page 5 of this report, recent volatility in the credit markets calls for a change in how PFM would suggest developing reasonable assumptions to be used in the 2007 Supplemental 7(b)(2) Case. PFM recommends revising the prior Rate Test Study practice of using the most recent ten years of interest rate data, and instead utilizing the most recent three years of data as a reasonable assumption for the purpose of the current Rate Test Study. While future market conditions remain uncertain, PFM is of the opinion that utilizing the recent three year period will reflect that likelihood that some degree of market disruption is likely to persist for at least a portion of the period covered by the current Rate Test Study. For this reason, we have based our future interest rate assumptions for each of the various financing structures on the data from July 15, 2005 and forward.

TABLE B - Historical Interest Rate Assumptions From Prior 7(b)(2) Rate Studies

FY End 9/30	Revenue Bond Index	BPA Rate	JOA Rate	Difference
1982	13.25%	12.65%	13.31%	0.66%
1983	10.13%	9.86%	10.47%	0.61%
1984	10.43%	10.69%	10.74%	0.05%
1985	9.90%	10.35%	10.10%	-0.25%
1986	8.26%	8.49%	8.42%	-0.07%
1987	7.68%	7.77%	7.68%	-0.09%
1988	8.40%	8.50%	8.48%	-0.02%
1989	7.17%	7.01%	7.13%	0.12%
1990	7.51%	7.62%	7.49%	-0.13%
1991	7.20%	6.96%	7.02%	0.06%
1992	6.69%	6.33%	6.35%	0.02%
1993	6.06%	5.73%	5.81%	0.08%
1994	6.08%	5.63%	5.98%	0.35%
1995	6.57%	6.34%	6.51%	0.17%
1996	6.01%	5.80%	5.96%	0.16%
1997	5.87%	5.61%	5.76%	0.15%
1998	5.41%	5.15%	5.31%	0.16%
1999	5.41%	5.14%	5.24%	0.10%
2000	6.07%	5.82%	5.92%	0.10%
2001	5.53%	5.26%	5.42%	0.16%
2002	5.42%	5.10%	5.34%	0.24%
2003	5.15%	4.89%	5.19%	0.30%
2004	5.13%	4.87%	5.10%	0.23%

Based on the Bloomberg Fair Market yield curves over the past three years, the average AA-rated, 25-year electric revenue bond yield was 4.51%%. This figure represents a 22 basis point advantage relative to the 4.73% average for the A-rated average for the comparable period. Table C provides these figures for the past three fiscal years.

TABLE C – Recent Average AA and A Rated, 25-Year Electric Revenue Bonds

Year End 7/15	Program Case AA Bloomberg BPA Rate	7(b)(2) Case A Bloomberg JOA Rate	Difference
2006	4.50%	4.71%	0.21%
2007	4.38%	4.58%	0.20%
2008	4.65%	4.91%	0.26%
Averages	4.51%	4.73%	0.22%

For the 2007 Supplemental Power Rate Case Financing Cost Study, we have been advised by BPA personnel of the potential consideration of resource financings that would have repayment periods greater than 30 years. Specifically, there is consideration to potential financing of generation resources that would have terms of 35 years. Our analysis indicates that the average rates listed above of 4.51% and 4.73% would have each been 3 basis points higher for 35-year maturities. We were also advised that the financing terms for conservation investments would be for 15 and 20 year terms, depending on the vintage year of the prior conservation investments made by BPA through its customers, and pending decisions on how the first-year expensed costs might be treated as deferred charges (SFAS #71) and financed over 5 years. Tables D, E, F, and G below provides various historical and projected interest rate assumptions for borrowings with final maturities of 5, 10, 15, and 20-years.

TABLE D – 20-Year Term Structure Interest Rate Assumptions

Year End 7/15	Program Case ‘AA’ Bloomberg BPA Rate	7(b)(2) Case ‘A’ Bloomberg JOA Rate	Difference
2006	4.43%	4.64%	0.21%
2007	4.36%	4.56%	0.20%
2008	4.60%	4.84%	0.24%
Averages	4.46%	4.68%	0.22%

TABLE E – 15-Year Term Structure Interest Rate Assumptions

Year End 7/15	Program Case ‘AA’ Bloomberg BPA Rate	7(b)(2) Case ‘A’ Bloomberg JOA Rate	Difference
2006	4.28%	4.47%	0.19%
2007	4.28%	4.46%	0.18%
2008	4.43%	4.66%	0.23%
Averages	4.33%	4.53%	0.20%

TABLE F – 10-Year Term Structure Interest Rate Assumptions

Year End 7/15	Program Case 'AA' Bloomberg BPA Rate	7(b)(2) Case 'A' Bloomberg JOA Rate	Difference
2006	4.03%	4.18%	0.15%
2007	3.99%	4.19%	0.20%
2008	4.00%	4.24%	0.24%
Averages	4.01%	4.20%	0.19%

TABLE G – 5-Year Term Structure Interest Rate Assumptions

Year End 7/15	Program Case BPA Rate[1]	7(b)(2) Case A Bloomberg JOA Rate	Difference
2006	3.62%	3.77%	0.15%
2007	3.75%	3.95%	0.20%
2008	3.38%	3.64%	0.26%
Averages	3.58%	3.79%	0.21%

<u>Note 1</u> - During the 2007 Supplemental Power Rate Case study period FY 2009 – FY 2013, BPA projects that it will borrow $192 million for conservation investments using five-year maturities with a weighted average interest rate of 5.90%. The bonds will be issued through the U.S. Treasury so they are not comparable to the tax exempt rates included in the table.

The period averages listed above would serve as the assumed interest rates for the 2007 Supplemental 7(b)(2) Cases' prospective 20, 15, 10 and 5-year financings. To determine the rates for bonds issued with maturities between 5 and 10 years, it would be reasonable to interpolate the rates between the 5 and 10-year maturities as being in between this range. For example the rate for 6-year maturities would represent the 5-year maturity plus 1/5th of the difference between 5 and 10-year maturities.

In our opinion, the above-assumed projected borrowing rates are reasonable estimates for borrowing costs of municipal issuers during the 2009-2013 time period. Many factors influence the movement of tax-exempt interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are: the timing of particular financings; the absolute levels of interest rates; the perceived credit quality of particular issuers; and the overall supply and demand for tax -exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease, which would change the assumed borrowing interest rate differentials calculated above.

SECTION 9
NON-7(b)(2) CUSTOMER BORROWING COSTS

Private developers, industrial companies, utility subsidiaries, governmental and quasi-governmental entities all represent viable sponsors for developing power projects whose output could be made available to BPA. Financing vehicles available to project sponsors will be either recourse, where the sponsor's balance sheet is relied upon for credit support, or non-recourse. In a non-recourse project financing, the strength of the project, not the strength of the sponsor, provides the support for the debt. Project financings would derive considerable financing benefits from inclusion of a BPA power purchase contract.

For the purposes of this analysis, it is assumed that BPA would enter into an all encompassing power purchase agreement whereby BPA would be obligated to pay an amount sufficient to cover a project's fixed and variable costs. As a result, the project's financing should be indifferent to the level of electricity actually purchased. Other factors including power delivery requirements, security deposits, performance criteria, regulatory out provisions, milestone criteria, force majeure events, security interests, events of default and remedies upon default are presumed to be resolved in a fashion that enables a project to be financed upon standard commercial terms.

Project sponsors which are private entities may or may not be able to qualify for tax-exempt financing for a particular project and generally may do so only where a facility qualifies as an "exempt facility" such as a waste to energy facility. Projects financed with tax-exempt financing would likely occur at interest rates comparable to those for the hypothetical JOA discussed in section 8. Projects financed with private sources of capital would likely be financed with high leverage, which is usually 75 or 80 percent but can be as much as 100 percent, which allows for a minimization of equity investment by the project sponsor. We assume that a project financing with a BPA contract would provide the means for securing debt financing at pricing which would be at the upper end of the quality range for similar projects. The perceived credit quality of the BPA contract obligation among potential financing sources would increase financing options for a given project.

As in the Final 2007 Power Rate Cases' Financing Cost Study, for purposes of historical non-7(b)(2) resource financing, we again feel it is reasonable to utilize the historical interest rate methodology contained in the Pre-2007 Rate Studies for the 7(b)(2) Rate Test. Pre-2007 Rate Studies have assumed that private debt financing for a project with a BPA contract could have been arranged at 50 basis points over the lender's cost of funds, which was assumed to have been the six-month's London Interbank Offered Rate (LIBOR), with 100 percent financing of project costs. The prior financing studies then adjusted for the possible effects of entering into interest rate swaps or conversion agreements which could have the effect of fixing the interest rates on all or a portion of a financing for a period of time or the remaining term to maturity for the transaction. In order to adjust the variable LIBOR interest rates to an estimated fixed interest rate for comparison purposes, prior financing studies assumed a 50 basis point addition to the LIBOR based interest rates to represent the amortized cost of an interest rate swap. Table H below provides the 17-year history of monthly averages for six-month LIBOR utilized in the Prior 2002 Study, along with the calculated borrowing rates for the same period. Table H also provides the JOA rates utilized in the Prior 2002 Study. The assumptions are the same as those listed and discussed in Section 8.

TABLE H - Historical Interest Rate Assumptions From Pre-2002 7(b)(2) Rate Studies

FY End 9/30	6-Mo. LIBOR	Adjusted Non 7(b)(2) Fixed Rate	JOA Rate	Difference
1982	15.41%	16.41%	13.31%	-3.10%
1983	10.29%	11.29%	10.47%	-0.82%
1984	11.27%	12.27%	10.74%	-1.53%
1985	9.57%	10.57%	10.10%	-0.47%
1986	7.65%	8.65%	8.42%	-0.23%
1987	6.55%	7.55%	7.68%	0.13%
1988	7.67%	8.67%	8.48%	-0.19%
1989	9.38%	10.38%	7.13%	-3.25%
1990	8.27%	9.27%	7.49%	-1.78%
1991	6.85%	7.85%	7.02%	-0.83%
1992	4.22%	5.22%	6.35%	1.13%
1993	3.41%	4.41%	5.81%	1.40%
1994	4.29%	5.29%	5.98%	0.69%
1995	6.25%	7.25%	6.51%	-0.74%
1996	5.37%	6.37%	5.96%	-0.41%
1997	5.53%	6.53%	5.76%	-0.77%
1998	5.74%	6.74%	5.31%	-1.43%

Once again, the greater amounts of historical data and proliferation of market indices allowed us to refine the methodology from that used in the Pre-2007 Rate Studies. For more recent years' interest rate assumptions, and for the 2007 Supplemental Power Rate Case we suggest utilizing the Bloomberg database of interest rates for AA-rated, 25-year taxable utility bonds as the best proxy for potential non-7(b)(2) project financing costs. As previously described, we have based our future interest rate assumptions for each of the various financing structures on the recent three-year data set from July 15, 2005 to July 15, 2008. Table I below provides the past three years' averages for the Bloomberg AA-rated, 25-year utility bonds as compared to the JOA financing costs assumed for the same periods. Again, the JOA financing cost assumptions are those provided in Section 8.

TABLE I - Recent Average Bloomberg AA and A Rated, 25-Year Electric Revenue Bonds

Year End 7/15	AA Bloomberg Taxable Utility Non 7(b)(2) Rate	A Bloomberg Tax-Exempt Bond JOA Rate	Difference
2006	5.79%	4.71%	-1.08%
2007	5.83%	4.58%	-1.25%
2008	6.06%	4.91%	-1.15%
Averages	5.89%	4.73%	-1.16%

In our opinion, the above-assumed borrowing rates are reasonable estimates based upon the actual borrowing costs of taxable and tax-exempt borrowers the indicated time periods. Many factors influence the movement of interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are: the timing of particular financings; the absolute levels of interest rates; the perceived credit quality of particular issuers; and the overall supply and demand for tax-exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease, which would change the assumed borrowing interest rate differentials calculated above.

ATTACHMENT A

PARTICIPATION IN HYPOTHETICAL PUBLIC FINANCING ENTITY

PARTICIPANTS	AVERAGE FINANCIAL RATING[1]	% SHARE
Generators:		
Eugene Water and Electric Board	A	3.70%
Seattle	A	13.72
Tacoma	A	6.66
PUD #1 of Chelan County	AA	2.53
PUD #1 of Cowlitz County	A	6.35
PUD #1 of Douglas County	AA	.92
PUD # 2 of Grant County	AA	4.11
PUD #1 of Snohomish County	AA	9.41
PUD #1 of Clark	A	6.00
PUD #1 of Lewis County	A	1.10
SUBTOTAL – GENERATORS (9)	A	54.50%
Non-Generators:		
Springfield	A	1.24
PUD #1 of Benton County	A	2.44
Central Lincoln County PUD	A	1.67
Clatskanie PUD	BBB	1.21
Franklin PUD	A	1.12
PUD #1 OF Grays Harbor County	A	1.73
Umatilla Electric Cooperative Association	NA	1.14
SUBTOTAL – NONGENERATORS WITH GREATER THAN 1% SHARE (8)	A	10.55%
SUBTOTAL – REMAINING NONGENERATORS (100)	NA	34.95%
TOTAL (117)	A	100.00%

Note 1 – Rating represents the average of the latest reports issued by Standard and Poor's, Moody's, and Fitch rating agencies as of July 2008. The average rating is calculated by assigning a score, 1 to 10, with 1 being a 'AAA' and 10 being a 'BBB-", to the top ten rating categories for each agency and then taking the average score for each issuer. The average score was then assigned a rating of either 'AAA', 'AA', 'A', or 'BBB' based on the range with which it fell.

APPENDIX B

Section 7(b)(2)
Rates Analysis Model - Resource Stack

Used in Revising FY 2009 Rates

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WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack - FY 2009 Revised Rates

Introduction - Summary Information - Table of Contents

The detailed amounts and costs for conservation resources are contained in Appendix D to the 7 (b)(2) Study.

The detailed amounts and costs for non-conservation resources are contained in Appendix C to the 7 (b)(2) Study. The summary resource cost information cost values that are contained in the resource stack in 1980 dollars are presented at Appendix C.

7b2 New Resource Sort **7b2 Resource_03**

All Costs are in 1980 dollars

NO LOST REVENUES INCLUDED IN COSTS

BPA & Public resources
*** The following resources are listed least cost first

A Project		B Nameplate (MW)	C Interest Rate (%)	D Capital Investment ($ooo)	E Annual O & M ($ooo)	F Annual Fuel ($ooo)	G Year Available	H Capacity Factor	I Life	J Annual Capital Cost ($ooo)	K Total Discounted Capital Cost ($ooo)	L Total Discounted O & M and Fuel ($ooo)	M Total Cost Dollars per AMW ($)	M Total Cost Mills per KWH	Conservation	
WANAPAM 1963 ND	1963	10.00		0	581	0	2009	100	70	0	0	9,611	13,729	1.57	581	**N**
PRIEST RAPIDS 1959 ND	1959	17.70		0	1,075	0	2009	100	70	0	0	17,779	14,349	1.64	1075	**N**
BOARDMAN PUBLIC ND	1980	49.71			4,453	0	2009	100	60	1,551	25,286	72,614	32,823	3.75	6004	N
BPA PROG CONS	2004	31.00	4.53	9,368	7,627	0	2009	100	15	874	8,523	7,627	34,731	3.96	874	**Y**
BPA PROG CONS	2001	18.50	4.53	29	10,238	0	2009	100	15	3	27	10,238	36,991	4.22	3	**Y**
BPA PROG CONS	2000	14.70	4.53	183	8,092	0	2009	100	15	17	166	8,092	37,452	4.28	17	**Y**
IDAHO FALLS ND	1982	18.50		0	2,590	0	2009	100	60		0	42,229	38,044	4.34	2590	N
BPA PROG CONS	2006	30.20	4.53	6,785	12,697	0	2009	100	15	633	6,173	12,697	41,655	4.76	633	**Y**
BPA PROG CONS	1999	30.30	4.53	10,576	11,074	0	2009	100	15	987	9,621	11,074	45,534	5.20	987	**Y**
BPA PROG CONS	2007	28.50	4.53	4,726	17,122	0	2009	100	15	441	4,299	17,122	50,109	5.72	441	**Y**
BPA PROG CONS	2003	24.70	4.53	11,323	8,547	0	2009	100	15	1,056	10,301	8,547	50,871	5.81	1056	**Y**
BPA PROG CONS	2005	20.00	4.53	6,898	10,498	0	2009	100	15	644	6,276	10,498	55,912	6.38	644	**Y**
BPA PROG CONS	2002	25.70	4.53	14,231	8,643	0	2009	100	15	1,328	12,947	8,643	56,006	6.39	1328	**Y**
COWLITZ FALLS	1994	26.00	4.25	0	0	0	2009	100	60	6,498	105,958	0	67,922	7.75	6498	N
BPA PROG CONS	2008	34.70	4.53	6,463	30,904	0	2009	100	15	603	5,880	30,904	70,671	8.07	603	**Y**
BPA PROG CONS	2009	34.70	4.53	13,517	31,228	0	2009	100	15	1,261	12,297	31,228	83,622	9.55	1261	**Y**
BPA PROG CONS	2013	39.50	4.53	21,864	34,863	0	2009	100	15	2,040	19,892	34,863	92,412	10.55	2040	**Y**
BPA PROG CONS	2011	39.50	4.53	22,764	34,758	0	2009	100	15	2,124	20,710	34,758	93,618	10.69	2124	**Y**
BPA PROG CONS	2012	39.50	4.53	22,308	35,273	0	2009	100	15	2,081	20,295	35,273	93,786	10.71	2081	**Y**
WAUNA-Steam-Cogen.	1996	23.00		0	4,711	0	2009	100	30	0	0	65,269	94,592	10.80	4711	N
BPA PROG CONS	2010	39.50	4.53	23,206	35,142	0	2009	100	15	2,165	21,112	35,142	94,944	10.84	2165	**Y**
BILLING CREDITS	1996	11.80		0	2,434	0	2009	100	30	0	0	33,716	95,242	10.87	2434	N
NINE CANYON WIND PROJ. NI	2008	13.52		0	3,201	0	2009	100	35	0	0	46,737	98,769	11.27	3201	N

BPA's Wholesale Power 2007 Supplemental Rate Case
FY 2009 Revised Rates
BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures
BPA 2007 Rate Case 7(b)(2) Resource Stack - Annual Investments and Savings

($ 000)

NOMINAL DOLLARS IN THE YEAR OF INVESTMENT

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	Conser. Savings aMW		Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Capitalized Amort. Period Years	First-Year Expense Deferral Period Years
1999 Conser.	30.3		20,657.0	19,728.0	40,385.0	15	7
2000 Conser.	14.7		15,377.0	347.0	15,724.0	15	7
2001 Conser.	18.5		19,905.0	57.0	19,962.0	15	7
2002 Conser.	25.7		17,143.0	28,227.0	45,370.0	15	7
2003 Conser.	24.7		17,286.0	22,900.0	40,186.0	15	7
2004 Conser.	31.0		15,821.0	19,431.0	35,252.0	15	7
2005 Conser.	20.0		22,446.0	14,750.0	37,196.0	15	7
2006 Conser.	30.2		28,014.0	14,970.0	42,984.0	15	7
2007 Conser.	28.5		38,860.0	10,725.0	49,585.0	15	7
2008 Conser.	34.7		71,724.0	15,000.0	86,724.0	15	7
2009 Conser.	34.7		73,932.0	32,000.0	105,932.0	15	7
2010 Conser.	39.5		84,804.0	56,000.0	140,804.0	15	7
2011 Conser.	39.5		85,504.0	56,000.0	141,504.0	15	7
2012 Conser.	39.5		88,548.0	56,000.0	144,548.0	15	7
2013 Conser.	39.5		89,292.0	56,000.0	145,292.0	15	7
Cumulative Savings 1999-2013	**451.0**	aMW	**$689,313.0**	**$402,135.0**	**$1,091,448.0**		
Percentages			63.16%	36.84%	100.00%		

BPA's Wholesale Power 2007 Supplemental Rate Case
FY 2009 Revised Rates
BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures
BPA 2007 Rate Case 7(b)(2) Resource Stack - Annual Investments and Savings

($ 000)

INVESTMENTS IN 1980 DOLLARS

Inflation / GDP Deflator Indicies Based on Global Insight Data - 04/03/2008

Inflation Adjustment Factor To Change To $ 1980		Conser. Savings aMW		Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Capitalized Amort. Period Years	First-Year Expense Deferral Period Years
1.865409	1999 Conser.	30.3		11,073.7	10,575.7	21,649.4	15	7
1.900276	2000 Conser.	14.7		8,092.0	182.6	8,274.6	15	7
1.944139	2001 Conser.	18.5		10,238.5	29.3	10,267.8	15	7
1.983459	2002 Conser.	25.7		8,643.0	14,231.2	22,874.2	15	7
2.022504	2003 Conser.	24.7		8,546.8	11,322.6	19,869.4	15	7
2.074232	2004 Conser.	31.0		7,627.4	9,367.8	16,995.2	15	7
2.138176	2005 Conser.	20.0		10,497.7	6,898.4	17,396.1	15	7
2.206339	2006 Conser.	30.2		12,697.1	6,785.0	19,482.0	15	7
2.269566	2007 Conser.	28.5		17,122.2	4,725.6	21,847.8	15	7
2.320833	2008 Conser.	34.7		30,904.4	6,463.2	37,367.6	15	7
2.367475	2009 Conser.	34.7		31,228.2	13,516.5	44,744.7	15	7
2.413169	2010 Conser.	39.5		35,142.2	23,206.0	58,348.2	15	7
2.459983	2011 Conser.	39.5		34,758.0	22,764.4	57,522.4	15	7
2.510354	2012 Conser.	39.5		35,273.1	22,307.6	57,580.7	15	7
2.561243	2013 Conser.	39.5		34,862.8	21,864.4	56,727.1	15	7
Cumulative Savings	**1999-2013**	**451.0**	aMW	296,707.0	174,240.3	470,947.3		
	Percentages			63.00%	37.00%	100.00%		

APPENDIX C

Non - Conservation Resources

Documentation of the Annual Amounts of Non - Conservation Resources Available

AND

Documentation of Resource Costs

Used in Revising FY 2009 Rates

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WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack - FY 2009 Revised Rates
Summary Information

1. **Billing Credit Resources - Revised Cost Projections:**

	BPA Billing Credits - 7(b)(2) Case Costs - 2009$$				BPA Billing Credits - 7(b)(2) Case Costs - 1980$$			
	Average	Total	Cost Per	Annual	Average	Total	Cost Per	Annual
Summary:	MWh	MW/Year	MWh	Cost	MWh	MW/Year	MWh	Cost
Project A	6.5468	57,350	$60.86	$ 3,490,270	6.5468	57,350	$25.71	$ 1,474,259
Project B	3.5939	31,483	$61.13	$ 1,924,520	3.5939	31,483	$25.82	$ 812,900
Project C	1.6530	14,480	$23.96	$ 346,881	1.6530	14,480	$10.12	$ 146,520
Annual Cost Data	11.7938	103,313	$55.77	$ 5,761,671	11.7938	103,313	$23.56	$ 2,433,678

Note 1 - The Program Case Revenue requirement includes the Smith Creek Hydro Project for the years of FY2007-2011. The Smith Creek Hydro Project contract terminates on September 30, 2011. Because this resource is not available to serve 7(b)(2) Customer loads during all years of the rate test period it was omitted from the 7(b)(2) Case resource stack. The costs and the average hourly energy amounts are not comparable between the Program Case and the 7(b)(2) Case.

Billing Credit Amounts for the Program Case:

	2007	2008	2009	2010	2011	2012	2013
Average Hourly Energy - aMW	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Annual Revenue Requirement Costs	$7,066,000	$7,137,000	$7,308,000	$7,383,000	$7,469,000	$5,873,000	$5,685,000

2. **Boardman Coal Plant - Revised Cost Projections - 10% PNGC/PRC Portion:**

7(b)(2) Case - Resource Stack Values:	FY 2009-$$	FY 1980-$$*
Total Annual O&M (Production Expenses)	10,542,109	4,452,891
Debt Service - FIXED - FY2009 - FY 2013	3,670,918	1,550,563
Total Operating and Financing Costs - (Production and Debt Service)	14,213,027	6,003,454
Cost per MWh	$32.64	$13.79
Capital Investment - Historical Cost as of FY 2007 - 10% Share	62,890,848	NA
Life	60 years	60 years
Placed in service	1980	1980
Net Continuous Plant Capability (MW)	58.5	58.5
Projected Net Annual Generation - MWh - PGE's 2008 Operating Budget	435,453	435,453
Capacity Factor	84.97%	84.97%
Projected Average Hourly Generation - aMW	49.71	49.71

Note 1- In order for the FY 2007-2008 Lookback rates model to hold the $1,550,563 of debt service (expressed in 1980 dollars) constant in all years of the rate test period after it was chosen, this amount was entered into the annual capital cost column of the "7(b)(2) Resource Sort" tab in the rates model. The $4,452,891 in O&M costs (expressed in 1980 dollars) were entered into the annual O&M column of the "7(b)(2) Resource Sort" tab in the rates model.

3. **Cowlitz Falls Hydro Project - Revised Cost Projections:**

	FY 2009-$$	FY1980-$$*
7(b)(2) Case - Resource Stack Values:		
Total O&M - 5-year average FY 2009 - FY 2013	3,752,560	1,585,047
Debt Service - FIXED - FY2009 - FY 2013	11,630,516	4,912,625
Total Combined Costs - O&M and Debt Service	15,383,076	6,497,672
Cost per MWh	$67.54	$28.53
Capital Investment	195,148,632	NA
Life	30 years	30 years
Placed in service	1994	1994
Average Annual Energy Output/@ 26.0MWh2	227,760	227,760

Note 1- In order for the FY 2009 Revised rates model to hold the $6,497,672 (expressed in 1980 dollars) constant in all years of the rate test period, this amount was entered into the annual capital cost column of the "7(b)(2) Resource Sort" tab in the rates model. The O&M is declining from $3,759,500 in 2009 to $3,715,800 in FY 2011, so the 5-year average of FY2009-FY2013 was entered as a constant, rather than having it escalate for the time value of money.

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4. **Idaho Falls Hydro Project - Revised Cost Projections:**

			FY 2009-$$	FY1980-$$*
7(b)(2) Case - Resource Stack Values:				
Annual Power Purchase Cost	162,030 MWh's @	$37.83	$6,130,730	$2,589,565
Placed in service			1982	1982
Average Annual Energy Output/@ 18.5.0MWh3			162,060	162,060
Average Hourly Energy aMW3			18.50	18.50
Cost per MWh			$37.83	$15.98

Note 1 - Projected Contract Pricing MWH - $39.05 at contract cap rate, cost of power is expected to be at the cap during the rate test period. Only one month in FY 2007 was billed at a rate below the contract cap. Due to model escalation of O&M, the beginning FY 2009 amount was adjusted down to $37.83 so that the average escalated rate during the rate test period was less than the average Program Case rate during the rate test period.

Note 2 - Firm average energy value (aMW) was obtained from Table 5 of the March 2007 BPA, 2007 Pacific Northwest Loads and Resources Study on page 23.

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack - FY 2009 Revised Rates
Summary Information

5. **Nine Canyon Wind Project - Revised Cost Projections:**

7(b)(2) Resource Stack Amounts:		FY 2009$$	FY1980-$$*
Portions Not Dedicated to Native Load:			
Revenue Requirement Allocation to Non-Dedicated Portions =	48.00%	$7,578	$3,201
Share of total net annual generation (MWh)		118,459	118,459
Average energy per hour (aMW) / Name Plate rating times Capacity Factor		13.52	13.52
Share of name plate rating (MW)		46.03	46.03
Cost of Power ($/MWh)		$63.97	$27.02

6. **Priest Rapids Hydro Project - Revised Cost Projections:**

7(b)(2) Case - Resource Stack Values:	FY 2009-$$	FY 1980-$$*
Total Operating Costs - FY 2009 Non-dedicated COU & Marketer Projection	$2,545,086	$1,075,021
= 17.7aMW * $16.4144/MWh * 8,760 hours / year		
Cost per MWh	$16.41	$6.93
Capital Investment - Projected Net Utility Plant FY 2007 per Financial Statement	$189,610,161	NA
Life	70-100 years	70-100 years
Placed in service	1959	1959
Non-dedicated COU & Marketer average hourly energy (aMW) five-year average FY2009-2013	17.7	17.7
Average Annual Energy Output/@ 17.7MWh	155,052	155,052

7. **Wanapum Hydro Project - Revised Cost Projections:**

7(b)(2) Case - Resource Stack Values:	**FY 2009-$$**	**FY1980-$$***
Total O&M - FY 2009 Non-dedicated COU & Marketer Projection	$1,375,644	$581,060
= 10.0aMW *$15.7037/MWh*8,760 hour /year		
Cost per MWh	$15.70	$6.63
Capital Investment - Projected Net Utility Plant FY 2007 per Financial Statement	$362,467,399	NA
Life	70-100 years	70-100 years
Placed in service	1963	1963
Non-dedicated COU & Marketer average hourly energy (aMW) five-year average FY2009-2013	10.0	10.0
Average Annual Energy Output/@ 10.0MWh	87,600	87,600

8. **Wauna CoGeneration Resource - Revised Cost Projections:**

7(b)(2) Case - Resource Stack Values:	**FY2009-$$**	**FY1980-$$***
Annual Power Purchase Cost - See Note 1	$11,153,933	$4,711,320
Placed in service	1996	1996
Average Annual Energy Output/@ 23.0MWh2	201,480	201,480
Cost per MWh	$55.36	$23.38

Note 1 - After a resource is chosen by the rates model, its annual costs (stated in 1980 "real dollars") are inflated by the GDP deflator values contained in the model to the nominal dollars of the year the resource is selected. These costs are escalated for each of the remaining years of the rate test period. The contract price was adjusted to ensure that the cost for this resource in the 7(b)(2) Case does not exceed the costs that were included for the Program Case revenue requirement.

Note 2 - Firm average energy value (aMW) was obtained from Table 5 of the March 2007 BPA 2007 Pacific Northwest Loads and Resources Study, page 23.

* Deflator conversion factor of 2.367475 was used to convert the resource cost data that is expressed in 2009 dollars to 1980 dollars.
Global Insight Deflator Value to convert 2009$$ to 1980$$ = 2.367475

WP-07 Supplemental Rate Case
Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts
Forecasted Cost of Resource During FY2009-2013
FY 2009 Revised Rates - Resource Stack - Detail Information

Billing Credit Summary

	BPA Billing Credits - 7(b)(2) Case Costs - 2009$$				BPA Billing Credits - 7(b)(2) Case Costs - 1980$$			
Summary:	Average MWh	Total MW/Year	Cost Per MWh	Annual Cost	Average MWh	Total MW/Year	Cost Per MWh	Annual Cost
Project A	6.5468	57,350	$60.8591	$3,490,270	6.5468	57,350	$25.71	$1,474,259
Project B	3.5939	31,483	$61.1289	$1,924,520	3.5939	31,483	$25.82	$812,900
Project C	1.6530	14,480	$23.9551	$346,881	1.6530	14,480	$10.12	$146,520
	11.7938	103,313	$55.77	$5,761,671	11.7938	103,313	$23.56	$2,433,678
Annual Cost Data	11.7938	103,313	$55.77	$5,761,671	11.7938	103,313	$23.56	$2,433,678

GDP - Deflator to convert 2009$$ to 1980$$ = 2.367475

Note 1 - The Program Case Revenue requirement includes the Smith Creek Hydro Project for the years of FY2007-2011. The Smith Creek Hydro Project contract terminates on September 30, 2011. Because this resource is not available to serve 7(b)(2) Customer loads during all years of the rate test period it was omitted from the 7(b)(2) Case resource stack. The costs and the average hourly energy amounts are not comparable between the Program Case and the 7(b)(2) Case.

Billing Credit Amounts for the Program Case

	2007	2008	2009	2010	2011	2012	2013
Average Hourly Energy - aMW	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Annual Revenue Requirement Costs	$7,066,000	$7,137,000	$7,308,000	$7,383,000	$7,469,000	$5,873,000	$5,685,000

Billing Credit Resources - Detail

Project A - South Fork Tolt Hydro Project

				Final 2007-2009 Rates				Declared Project Generation								
Month	**Hours**	HLH	LLH	HLH $/MWh	LLH $/MWh	Demand $/kW	Ld Var $/MWh	HLH MWh	LLH MWh	Demand kW	Alt Cost $/MWh[2]	PF Power Only $	PTP-06 1.628	AC$ $	PF Power plus Tx $	**Billing Credit** $
October	744	416	328	29.70	21.76	1.94	0.47	4085	0	11200	96.7	143,053	24,420	395,020	167,473	227,547
November	721	416	305	31.68	23.10	2.08	0.47	3966	0	11200	96.7	148,939	24,420	383,512	173,359	210,153
December	744	432	312	33.06	24.26	2.18	0.47	4136	0	11200	96.7	161,152	24,420	399,951	185,572	214,379
January	744	432	312	28.07	20.30	1.85	0.47	4158	0	11300	96.7	137,620	24,420	402,079	162,040	240,039
February	672	368	304	28.66	20.50	1.88	0.47	3783	0	11300	96.7	129,665	24,420	365,816	154,085	211,731
March	743	432	311	26.59	19.49	1.75	0.47	4180	0	11300	96.7	130,921	24,420	404,206	155,341	248,865
April	720	416	304	24.95	17.93	1.64	0.47	4060	0	11300	96.7	119,829	24,420	392,602	144,249	248,353
May	744	416	328	20.84	14.41	1.36	0.47	4933	0	12300	96.7	119,532	24,420	477,021	143,952	333,069
June	720	416	304	18.87	10.02	1.25	0.47	5710	0	13600	96.7	124,748	24,420	552,157	149,168	402,989
July	744	432	312	23.24	17.01	1.53	0.47	6993	0	15000	96.7	185,467	24,420	676,223	209,887	466,336
August	744	416	328	27.21	20.18	1.79	0.47	6702	0	14700	96.7	208,674	24,420	648,083	233,094	414,989
September	720	416	304	28.09	22.54	1.85	0.47	4644	0	12100	96.7	152,835	24,420	449,075	177,255	271,820
	8,760	5,008	3,752					57,350	0	146,500		1,762,435	293,040	5,545,745	2,055,475	3,490,270
							Average MWh	**6.5468**					**Annual Cost per MWh**			**60.8591**

Note 2 - Alternative cost value is the average of FY2009-2013 contract schedule, Exhibit C, Table 3.

WP-07 Supplemental Rate Case
Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts
Forecasted Cost of Resource During FY2009-2013
FY 2009 Revised Rates - Resource Stack - Detail Information

Project B - Wynochee Hydro Project

				Final 2007-2009 Rates				Declared Project Generation									
Month	**Hours**	HLH	LLH	HLH $/MWh	LLH $/MWh	Demand $/kW	Ld Var $/MWh	HLH MWh	LLH MWh	Assured Energy Capabilities	Demand kW	Alt Cost[3] $/MWh	**AC$** $	PTP-06 1.628	PF Power Costs Only $	**PF Power Plus Tx** $	**Billing Credit** $
October	744	416	328	29.70	21.76	1.94	0.47	2,043	1,611	3,654	4,910	92.76	338,945	10,452	105,259	115,710	223,235
November	721	416	305	31.68	23.10	2.08	0.47	2,428	1,781	4,209	5,850	92.76	390,427	10,452	130,232	140,684	249,743
December	744	432	312	33.06	24.26	2.18	0.47	3,042	2,197	5,239	7,040	92.76	485,970	10,452	169,215	179,667	306,303
January	744	432	312	28.07	20.30	1.85	0.47	2,775	2,004	4,779	6,420	92.76	443,300	10,452	130,452	140,903	302,397
February	672	368	304	28.66	20.50	1.88	0.47	2,315	1,912	4,227	6,290	92.76	392,097	10,452	117,367	127,819	264,277
March	743	432	311	26.59	19.49	1.75	0.47	1,425	1,026	2,451	3,290	92.76	227,355	10,452	63,646	74,097	153,257
April	720	416	304	24.95	17.93	1.64	0.47	1,117	816	1,933	2,680	92.76	179,305	10,452	46,894	57,346	121,959
May	744	416	328	20.84	14.41	1.36	0.47	0	0	0	0	92.76	-	10,452	-	-	-
June	720	416	304	18.87	10.02	1.25	0.47	0	0	0	0	92.76	-	10,452	-	-	-
July	744	432	312	23.24	17.01	1.53	0.47	1,045	754	1,799	2,420	92.76	166,875	10,452	40,811	51,263	115,612
August	744	416	328	27.21	20.18	1.79	0.47	912	719	1,631	2,190	92.76	151,292	10,452	43,245	53,696	97,595
September	720	416	304	28.09	22.54	1.85	0.47	902	659	1,561	2,170	92.76	144,798	10,452	44,205	54,657	90,142
	8,760	5,008	3,752					18,004	13,479	31,483	43,260		2,920,363	125,421	891,326	995,843	1,924,520

Average MWh **3.5939** **Annual Cost per MWh** **$61.1289**

Note 3 - Alternative cost value is the average of FY2009-2013 contract schedule, Exhibit C, page 10, Table 3.

Project C - Short Mountain Landfill Project

	Final 2007-2009 Rates						**Estimated**	**Sustained**									
	HLH Energy	LLH Energy	Demand	Load Variance	NT-08 Network Integration	LDD	**Firm Energy (MWh) 2/**	**Peaking Capability (MW)**	**Adjusted Alternative Cost 1/**	**AC$**	**HLH Energy 57% Split**	**LLH Energy 43% Split**	**Gen Demand**	**Load Variance**	**Trans Base / Load Shaping**	**PF$ Incls LDD**	**Billing Credits**
October	29.70	21.76	1.94	0.47	1.665	0.045	1,125.338	3.22	55.7	$62,704	$19,051	$10,530	$6,247	$529	$5,361	$40,081	$22,622
November	31.68	23.10	2.08	0.47	1.665	0.045	1,168.988	3.22	55.7	$65,136	$21,109	$11,612	$6,698	$549	$5,361	$43,530	$21,606
December	33.06	24.26	2.18	0.47	1.665	0.045	1,190.775	3.22	55.7	$66,350	$22,439	$12,422	$7,020	$560	$5,361	$45,892	$20,458
January	28.07	20.30	1.85	0.47	1.665	0.045	1,204.262	3.22	55.7	$67,101	$19,268	$10,512	$5,957	$566	$5,361	$40,031	$27,071
February	28.66	20.50	1.88	0.47	1.665	0.045	1,159.469	3.22	55.7	$64,606	$18,941	$10,221	$6,054	$545	$5,361	$39,513	$25,093
March	26.59	19.49	1.75	0.47	1.665	0.045	1,383.505	3.22	55.7	$77,089	$20,969	$11,595	$5,635	$650	$5,361	$42,462	$34,627
April	24.95	17.93	1.64	0.47	1.665	0.045	1,327.122	3.22	55.7	$73,947	$18,874	$10,232	$5,281	$624	$5,361	$38,796	$35,151
May	20.84	14.41	1.36	0.47	1.665	0.045	1,366.568	3.22	55.7	$76,145	$16,233	$8,468	$4,379	$642	$5,361	$33,746	$42,399
June	18.87	10.02	1.25	0.47	1.665	0.045	1,182.404	3.22	55.7	$65,884	$12,718	$5,095	$4,025	$556	$5,361	$26,747	$39,137
July	23.24	17.01	1.53	0.47	1.665	0.045	1,107.764	3.22	55.7	$61,725	$14,674	$8,103	$4,927	$521	$5,361	$32,315	$29,409
August	27.21	20.18	1.79	0.47	1.665	0.045	1,143.195	3.22	55.7	$63,699	$17,731	$9,920	$5,764	$537	$5,361	$37,785	$25,914
September	28.09	22.54	1.85	0.47	1.665	0.045	1,121.094	3.22	55.7	$62,467	$17,950	$10,866	$5,957	$527	$5,361	$39,073	$23,395
TOTALS							14,480.484			$806,853	$219,957	$119,573	$67,942	$6,806	$64,336	$459,971	$346,881

Average MWh **1.6530** **Annual Cost per MWh** **$23.9551**

1/ Adjusted Alternative Cost is taken from total column on page 12 of Exhibit C Revision 1, average for the five years 2009-2013.
2/ These amounts are final metered energy amounts for the 2007 operating year.

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2009 Revised Rates Resource Stack - Detail Information

10% Interest - Boardman Coal Plant - Revised Cost Projections for FY 2009 Revised Rates

7(b)(2) Case - Resource Stack Values:		
	FY2009-$$	**FY1980-$$***
Total Annual O&M (Production Expenses)	10,542,108	4,452,891
Debt Service - FIXED - FY2009 - FY 2013	3,670,918	1,550,563
Total Operating and Financing Costs - (Production and Debt Service)	14,213,026	6,003,454
Cost per MWh	**$32.64**	**$13.79**
Capital Investment - Historical Cost as of FY 2007 - 10% Share	62,890,848	NA
Life	60 years	60 years
Placed in service	1980	1980
Net Continuous Plant Capability (MW)	58.50	58.50
Projected Net Annual Generation - MWh - PGE's 2008 Operating Budget	435,453	435,453
Capacity Factor	84.97%	84.97%
Projected Average Hourly Generation - aMW	40.65	40.65

* Deflator conversion factor of 2.367475 was used to convert the resource cost data that is expressed in 2009 dollars to 1980 dollars.

Global Insight Deflator Value to convert 2009$$ to 1980$$ = 2.367475

Note 1- In order for the FY 2007-2008 Lookback rates model to hold the $1,550,563 of debt service (expressed in 1980 dollars) constant in all years of the rate test period after it was chosen, this amount was entered into the annual capital cost column of the "7(b)(2) Resource Sort" tab in the rates model. The $4,452,891 in O&M costs (expressed in 1980 dollars) were entered into the annual O&M column of the "7(b)(2) Resource Sort" tab in the rates model.

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Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2009 Revised Rates Resource Stack - Detail Information

Summary of FY 2009 Projected Operating and Financing Costs:

	BPA's Projected Boardman - 100% Operating Budget FY 2009	BPA's Projected Boardman - 10% Operating Budget FY 2009
Fuel Cost Data:		
Fuel Cost - FERC # 501	$ 1,903,930	$ 190,393
Fuel Oil Costs	0	0
Fuel Inventory Oil Purchase #151	838,379	83,838
Payroll Taxes #408	1,038,181	103,818
Other Misc. Electric Revenues #456	(612,616)	(61,262)
Fuel Inventory - Coal fixed O&M #151	1,971,395	197,140
Coal Fuel Costs #151- line 20 (From Fuel analysis)	65,354,285	6,535,429
TOTAL FUEL COSTS	70,493,554	7,049,355
Operating Cost Data:		
Production Expenses - line 19	7,235,190	723,519
Misc. Steam / Power Expenses FERC #506 & #557- line 26	2,314,150	231,415
Rent Expense #507- line 27	0	0
Allowances - line 28	0	0
Administrative & General Expenses #921-#930	6,078,386	607,839
TOTAL OPERATION COSTS	15,627,726	1,562,773
Maintenance Expense - line 29	19,299,804	1,929,980
Total Production Expenses	$ 105,421,084	10,542,108
Debt Service Costs (From Financing Plant Cost Analysis)		3,670,918
Total Operating and Financing Costs - 10% Boardman for FY 2009 in 2009$$		**$ 14,213,026**
Cost per MWh in 2009$$		**$32.64**
Costs Converted from 2009$$$ to 1980$$$:		
Total Production Expenses		4,452,891
Debt Service Costs		1,550,563
Total Operating and Financing Costs - 10% Boardman for FY 2009 in 1980$$		**$ 6,003,454**
Global Insight Deflator Value to convert 2009$$ to 1980$$ =	2.367475	
Cost per MWh in 1980$$		**$13.79**
Net Continuous Plant Capability (MW)	585	58.5
Projected Net Annual Generation - KWh	4,354,534,426	435,453,443
Projected Net Annual Generation - MWh	4,354,534	435,453
Capacity Factor	84.97%	84.97%
Projected Average Hourly Generation - aMW		49.71

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
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FY 2009 Revised Rates Resource Stack - Detail Information

Boardman Operating Cost Historical Data / OY 2008 PGE Operating Budget / FY 2009 Projection:

	PGE's FERC Form No. 1 Data - page 402, column (b), Total Plant Costs								Portland General Electric's Boardman 100% Budget OY 2008 in 2008 $$	BPA's Projected Boardman Operating Budget FY 2009
	FY2004	**FY2004** Restated in FY2007 $$	**FY2005**	**FY2005** Restated in FY2007 $$	**FY2006**	**FY2006** Restated in FY2007 $$	**FY2007**	**4-Year Ave Costs Stated in FY2007 $$**		
		0.9285115		0.957948		0.9865435		1.00000		1.021026
Fuel Cost Data:										
Fuel Cost - FERC # 501									1,864,722	1,903,930
Fuel Oil Costs										0
Fuel Inventory Oil Purchase #151								(* From fuel Cost Analysis)	813,962 *	838,379
Payroll Taxes #408									1,016,802	1,038,181
Other Misc. Electric Revenues #456									(600,000)	(612,616)
Fuel Inventory - Coal fixed O&M #151									1,930,798	1,971,395
Coal Fuel Costs #151- line 20	44,256,851	47,664,300	47,834,482	49,934,320	35,492,843	35,976,967	61,041,164	48,654,188	62,346,284 *	65,354,285
TOTAL FUEL COSTS	44,256,851	47,664,300	47,834,482	49,934,320	35,492,843	35,976,967	61,041,164	48,654,188	67,372,568	70,493,554
Operating Cost Data:										
Production Expenses - line 19	6,764,874	7,285,719	5,974,221	6,236,477	5,989,289	6,070,983	6,763,843	6,589,256	7,086,196	7,235,190
Misc. Steam / Power Expenses FERC #506 & #557- line 26	1,192,631	1,284,455	2,169,872	2,265,125	2,066,716	2,094,906	2,169,128	1,953,403	2,266,495	2,314,150
Rent Expense #507- line 27	3,618,051	3,896,614	1,138,860	1,188,854	257,963	261,482	0	1,336,737	0	0
Allowances - line 28	(7,770)	(8,368)	(19,387)	(20,238)	0	0	0	(7,152)	0	0
Administrative & General Expenses #921-#930									5,953,214	6,078,386
TOTAL OPERATION COSTS	11,567,786	12,458,420	9,263,566	9,670,218	8,313,968	8,427,371	8,932,971	9,872,245	15,305,905	15,627,727
Maintenance Expense - line 29	23,694,817	25,519,142	19,345,303	20,194,523	18,802,559	19,059,027	19,406,261	21,044,738	18,902,363	19,299,804
Total Production Expenses	79,519,454	85,641,862	76,443,351	79,799,061	62,609,370	63,463,365	89,380,396	79,571,171	101,580,836	105,421,085

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2009 Revised Rates Resource Stack
Analysis of Coal Fuel Cost

	2006	2007	2008
Oil Price Escalation			
Inflations Rate		2.00%	2.00%
Inflation Factor	100.0%	102.0%	104.0%
Coal ($2006) - Delivered Price - March 2008 # DOE/EIA-0383	33.85	34.52	35.23
Coal Nominal	$ 33.85	$ 35.21	$ 36.65
Percentage Chage in Coal Price (Nominal)		4.02%	4.10%

		Historical - FERC Form No. 1				PGE Budget
		2004	2005	2006	2007	2008
Net Continuous Plant Capability (MW)	**FERC Form 1, Page 402**	568	585	585	585	585
Hours Connected to load	**FERC Form 1, Page 402**	6,449	6,235	4,357	6,686	
Capacity Factor		71.14%	69.49%	47.11%	84.98%	84.98%
Fuel	**FERC Form 1, Page 402**	$ 44,256,851	$ 47,834,482	$ 35,492,843	$ 61,041,164	$ 62,346,284
Fuel Burned						
Quantity Coal (tons)	**FERC Form 1, Page 402**	2,119,299	2,103,125	1,435,147	2,577,187	2,586,135
Average Heat Content - Coal	**FERC Form 1, Page 402**	8,517	8,517	8,517	8,517	8,517
AVG Cost of Fuel - Coal - per unit burned	**FERC Form 1, Page 402**	$ 19.59	$ 20.80	$ 21.53	$ 22.86	$ 24.11
Average BTU / kWh (Heat Rate)	**FERC Form 1, Page 402**	10,198	10,060	10,125	10,081	10,116
Net Generation		3,539,923,433	3,561,096,546	2,414,448,790	4,354,707,207	4,354,707,207
Coal Cost (Total)		**41,517,067**	**43,745,000**	**30,898,715**	**58,914,495**	**62,346,284**
Quantity Oil	**FERC Form 1, Page 402**	11,960	7,418	8,006	6178	8390.5
Avg cost - Oil - per unit burned	**FERC Form 1, Page 402**	46.055	$ 57.53	$ 80.27	89.201	97.01
Oil cost Total		**$ 550,818**	**$ 426,758**	**$ 642,642**	**$ 551,084**	**$ 813,962**
Total Fuel Cost		**$ 42,067,885**	**$ 44,171,758**	**$ 31,541,357**	**$ 59,465,579**	**$ 63,160,246**

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2009 Revised Rates Resource Stack
Analysis of Coal Fuel Cost

	2009	2010	2011	2012	2013
Oil Price Escalation	3.00%	3.00%	3.00%	3.00%	3.00%
Inflations Rate	2.00%	2.00%	2.00%	2.00%	2.00%
Inflation Factor	106.1%	108.2%	110.4%	112.6%	114.9%
Coal ($2006) - Delivered Price - March 2008 # DOE/EIA-0383	36.19	36.63	36.06	35.24	34.73
Coal Nominal	$ 38.41	$ 39.65	$ 39.81	$ 39.69	$ 39.89
Percentage Chage in Coal Price (Nominal)	4.78%	3.24%	0.41%	-0.32%	0.52%

	Forecast - Projection				
	2009	2010	2011	2012	2013
Net Continuous Plant Capability (MW)	585	585	585	585	585
Hours Connected to load					
Capacity Factor	84.98%	84.98%	84.98%	84.98%	84.98%
Fuel					
Fuel Burned					
Quantity Coal (tons)	2,586,135	2,586,135	2,586,135	2,586,135	2,586,135
Average Heat Content - Coal	8,517	8,517	8,517	8,517	8,517
AVG Cost of Fuel - Coal - per unit burned	$ 25.26	$ 26.08	$ 26.19	$ 26.10	$ 26.24
Average BTU / kWh (Heat Rate)	10,116	10,116	10,116	10,116	10,116
Net Generation	4,354,707,207	4,354,707,207	4,354,707,207	4,354,707,207	4,354,707,207
Coal Cost (Total)	**65,326,093**	**67,442,738**	**67,721,126**	**67,504,779**	**67,858,393**
Quantity Oil	8390.5	8390.5	8390.5	8390.5	8390.5
Avg cost - Oil - per unit burned	99.92	102.92	106.01	109.19	112.46
Oil cost Total	**$ 838,381**	**$ 863,532**	**$ 889,438**	**$ 916,121**	**$ 943,605**
Total Fuel Cost	**$ 66,164,474**	**$ 68,306,270**	**$ 68,610,564**	**$ 68,420,900**	**$ 68,801,998**

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2009 Revised Rates Resource Stack
Analysis of Total Capitalized Cost - Debt Service Amounts for Revenue Requirement

		Cumulative Cost
1980 Additions	591,000,000	591,000,000
1981-2004 Additions	13,085,247	604,085,247
2005 Additions	18,145,870	622,231,117
2006 Retirements	(359,817)	621,871,300
2007 Additions - Agrees to FERC Form No. 1 for 2007, page 402	7,037,182	628,908,482
Total Asset Cost -line 17, FERC Form No. 1		628,908,482
2007 Construction Work in Progress - FERC Form No. 1 for 2007, page 216		2,516,237

Note: PGE's FERC Form 1 Indicates that the plant has a life of 60 years.

Initial Investment Amount

		Total AMT	PRC AMT	Payment Amounts
Total Capitalized Cost - 1980		591,000,000	59,100,000	
Debt/Capital Mix		80 /20	100 / 0	
Amount financed in 1980		472,800,000	59,100,000	
30 year Bond @10% in 1980	59,100,000	10.00%	10.00%	6,269,284
Refi. in 1990 - 30 yr. @ 8%	53,373,938	8.00%	8.00%	4,741,071
Refi. in 2000 - 30 yr. @ 6%	46,548,508	6.00%	6.00%	3,381,700
Payment amount - annual				

			Payment Amount	Interest	Principle	Balance
Beginning Balance						59,100,000
	1	1980	6,269,284	5,910,000	359,284	58,740,716
	2	1981	6,269,284	5,874,072	395,212	58,345,504
	3	1982	6,269,284	5,834,550	434,734	57,910,770
	4	1983	6,269,284	5,791,077	478,207	57,432,563
	5	1984	6,269,284	5,743,256	526,028	56,906,535
	6	1985	6,269,284	5,690,654	578,630	56,327,905
	7	1986	6,269,284	5,632,790	636,494	55,691,411
	8	1987	6,269,284	5,569,141	700,143	54,991,268
	9	1988	6,269,284	5,499,127	770,157	54,221,111
	10	1989	6,269,284	5,422,111	847,173	53,373,938
	11	1990	4,741,071	4,269,915	471,156	52,902,782
	12	1991	4,741,071	4,232,223	508,848	52,393,934
	13	1992	4,741,071	4,191,515	549,556	51,844,378
	14	1993	4,741,071	4,147,550	593,521	51,250,857
	15	1994	4,741,071	4,100,069	641,002	50,609,854
	16	1995	4,741,071	4,048,788	692,283	49,917,572
	17	1996	4,741,071	3,993,406	747,665	49,169,907
	18	1997	4,741,071	3,933,593	807,478	48,362,428
	19	1998	4,741,071	3,868,994	872,077	47,490,351
	20	1999	4,741,071	3,799,228	941,843	46,548,508
	21	2000	3,381,700	2,792,911	588,789	45,959,719
	22	2001	3,381,700	2,757,583	624,117	45,335,602
	23	2002	3,381,700	2,720,136	661,564	44,674,038
	24	2003	3,381,700	2,680,442	701,258	43,972,781
	25	2004	3,381,700	2,638,367	743,333	43,229,447
	26	2005	3,381,700	2,593,767	787,933	42,441,514
	27	2006	3,381,700	2,546,491	835,209	41,606,305
	28	2007	3,381,700	2,496,378	885,322	40,720,983
	29	2008	3,381,700	2,443,259	938,441	39,782,542
	30	2009	3,381,700	2,386,953	994,747	38,787,795
	31	2010	3,381,700	2,327,268	1,054,432	37,733,363
	32	2011	3,381,700	2,264,002	1,117,698	36,615,664
	33	2012	3,381,700	2,196,940	1,184,760	35,430,904
	34	2013	3,381,700	2,125,854	1,255,846	34,175,059
	35	2014	3,381,700	2,050,504	1,331,196	32,843,862
	36	2015	3,381,700	1,970,632	1,411,068	31,432,794

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Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2009 Revised Rates Resource Stack
Analysis of Total Capitalized Cost - Debt Service Amounts for Revenue Requirement

Debt Service Requirements - Physical Plant:

FIVE YEAR (FY 2009-2013) AVERAGE DEBT SERVICE = $\boxed{3,670,918}$

	FY 2007	FY 2008	FY 2009	FY 2010
Initial Investment Amount	3,381,700	3,381,700	3,381,700	3,381,700
FY 2005 and Prior Additions	213,871	213,871	213,871	213,871
FY 2007 Additions	55,437	55,437	55,437	55,437
FY 2008 Additions	0	19,910	19,910	19,910
TOTAL ANNUAL DEBT SERVICE	3,651,008	3,670,918	3,670,918	3,670,918

Second Debt financing amount for FY 2005 and prior Additions

	Total AMT	PRC AMT
Total Capitalized Cost - 1981-2006	31,231,117	3,123,112
Debt/Capital Mix	80 /20	100 / 0
Cap.Costs financed in 2005 10/01/2004	24,984,894	3,123,112
Financing Costs	493,960	12,888
Total Financing	25,478,854	3,136,000
30 year Bond @ 4.75% in 2005 - 1/	6.79%	5.42%
Payment amount - annual		$213,870.87

Note 1 - Interest rate from PFM financing study dated July 2006 Table I, page A-18

			Payment Amount	Interest	Principle	Balance
Beginning Balance						3,136,000
	1	2005	213,871	169,971	43,900	3,092,100
	2	2006	213,871	167,592	46,279	3,045,821
	3	2007	213,871	165,083	48,787	2,997,034
	4	2008	213,871	162,439	51,432	2,945,602
	5	2009	213,871	159,652	54,219	2,891,383
	6	2010	213,871	156,713	57,158	2,834,225
	7	2011	213,871	153,615	60,256	2,773,969
	8	2012	213,871	150,349	63,522	2,710,447
	9	2013	213,871	146,906	66,965	2,643,482
	10	2014	213,871	143,277	70,594	2,572,888
	11	2015	213,871	139,451	74,420	2,498,468
	12	2016	213,871	135,417	78,454	2,420,014
	13	2017	213,871	131,165	82,706	2,337,308
	14	2018	213,871	126,682	87,189	2,250,119
	15	2019	213,871	121,956	91,914	2,158,205
	16	2020	213,871	116,975	96,896	2,061,309
	17	2021	213,871	111,723	102,148	1,959,161
	18	2022	213,871	106,187	107,684	1,851,476
	19	2023	213,871	100,350	113,521	1,737,956
	20	2024	213,871	94,197	119,674	1,618,282
	21	2025	213,871	87,711	126,160	1,492,122
	22	2026	213,871	80,873	132,998	1,359,124
	23	2027	213,871	73,665	140,206	1,218,918
	24	2028	213,871	66,065	147,806	1,071,112
	25	2029	213,871	58,054	155,817	915,296
	26	2030	213,871	49,609	164,262	751,034
	27	2031	213,871	40,706	173,165	577,869
	28	2032	213,871	31,320	182,550	395,318
	29	2033	213,871	21,426	192,445	202,874
	30	2034	213,871	10,996	202,875	(1)

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2009 Revised Rates Resource Stack
Analysis of Total Capitalized Cost - Debt Service Amounts for Revenue Requirement

	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Initial Investment Amount	3,381,700	3,381,700	3,381,700	3,381,700	3,381,700
FY 2005 and Prior Additions	213,871	213,871	213,871	213,871	213,871
FY 2007 Additions	55,437	55,437	55,437	55,437	55,437
FY 2008 Additions	19,910	19,910	19,910	19,910	19,910
TOTAL ANNUAL DEBT SERVICE	3,670,918	3,670,918	3,670,918	3,670,918	3,670,918

FY 2007 Financing Amount

	Total AMT	PRC AMT
Total Capitalized Cost - 2007	7,037,182	703,718
Debt/Capital Mix	80 /20	100 / 0
Cap.Costs financed in 2007 10-01-2006	5,629,746	703,718
Financing Costs	20,254	6,282
Total Financing	5,650,000	710,000
20 year Bond @ 4.75% in 2007 - 1/	4.73%	4.68%
Payment amount - annual		55,436.70

Note 1 - Interest rate from PFM financing study dated 08/21/08, Table D, page 15

			Payment Amount	Interest	Principle	Balance
Beginning Balance						710,000
	1	2007	55,437	33,228	22,209	687,792
	2	2008	55,437	32,189	23,248	664,543
	3	2009	55,437	31,101	24,336	640,207
	4	2010	55,437	29,962	25,475	614,732
	5	2011	55,437	28,769	26,667	588,065
	6	2012	55,437	27,521	27,915	560,150
	7	2013	55,437	26,215	29,222	530,928
	8	2014	55,437	24,847	30,589	500,339
	9	2015	55,437	23,416	32,021	468,318
	10	2016	55,437	21,917	33,519	434,799
	11	2017	55,437	20,349	35,088	399,711
	12	2018	55,437	18,706	36,730	362,980
	13	2019	55,437	16,987	38,449	324,531
	14	2020	55,437	15,188	40,249	284,283
	15	2021	55,437	13,304	42,132	242,150
	16	2022	55,437	11,333	44,104	198,046
	17	2023	55,437	9,269	46,168	151,878
	18	2024	55,437	7,108	48,329	103,549
	19	2025	55,437	4,846	50,591	52,959
	20	2026	55,437	2,478	52,958	0

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Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2009 Revised Rates Resource Stack
Analysis of Total Capitalized Cost - Debt Service Amounts for Revenue Requirement

Assumes 2007 Consrtruction Work In Progress is completed and is transferred to the completed plant account in 2008.

FY 2008 Financing Amount

	Total AMT	PRC AMT
Total Capitalized Cost - 2008	2,516,237	251,624
Debt/Capital Mix	80 /20	100 / 0
Cap.Costs financed in 2008 10-01-2007	2,012,990	251,624
Financing Costs	20,011	3,376
Total Financing	2,033,000	255,000
20 year Bond @ 4.75% in 2007 - 1/	4.73%	4.68%
Payment amount - annual		19,910.36

Note 1 - Interest rate from PFM financing study dated 08/21/08, Table D, page 15

			Payment Amount	Interest	Principle	Balance
Beginning Balance						255,000
	1	2008	19,910	11,934	7,976	247,024
	2	2009	19,910	11,561	8,350	238,674
	3	2010	19,910	11,170	8,740	229,933
	4	2011	19,910	10,761	9,149	220,784
	5	2012	19,910	10,333	9,578	211,206
	6	2013	19,910	9,884	10,026	201,180
	7	2014	19,910	9,415	10,495	190,685
	8	2015	19,910	8,924	10,986	179,699
	9	2016	19,910	8,410	11,500	168,199
	10	2017	19,910	7,872	12,039	156,160
	11	2018	19,910	7,308	12,602	143,558
	12	2019	19,910	6,719	13,192	130,366
	13	2020	19,910	6,101	13,809	116,557
	14	2021	19,910	5,455	14,456	102,101
	15	2022	19,910	4,778	15,132	86,969
	16	2023	19,910	4,070	15,840	71,129
	17	2024	19,910	3,329	16,582	54,548
	18	2025	19,910	2,553	17,358	37,190
	19	2026	19,910	1,740	18,170	19,020
	20	2027	19,910	890	19,020	(0)

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections - Cowlitz Falls Hydro Project for FY 2009-2013
FY 2009 Revised Rates Resource Stack - Detail Information

Cowlitz Falls Hydro Project Resource - Revised Cost Projections for FY 2009 Revised Rates

7(b)(2) Case - Resource Stack Values:	FY2009-$$	FY1980-$$*
Total O&M - 5-year average FY 2009 - FY 2013	3,752,560	1,585,047
Debt Service - FIXED - FY2009 - FY 2013	11,630,516	4,912,625
Total Combined Costs - O&M and Debt Service	15,383,076	6,497,672
Cost per MWh	$67.54	$28.53
Capital Investment	195,148,632	NA
Life	30 years	30 years
Placed in service	1994	1994
Average Annual Energy Output/@ 26.0MWh[2]	227,760	227,760

* Deflator conversion factor of 2.367475, was used to convert the resource cost data that is expressed in 2009 dollars to 1980 dollars. 2.367475

Note 1- In order for the FY 2009 Revised rates model to hold the $6,497,672 (expressed in 1980 dollars) constant in all years of the rate test period, this amount was entered into the annual capital cost column of the "7(b)(2) Resource Sort" tab in the rates model. The O&M is declining from $3,759,500 in 2009 to $3,715,800 in FY 2011, so the 5-year average of FY2009-FY2013 was entered as a constant, rather than having it escalate for the time value of money.

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections - Cowlitz Falls Hydro Project for FY 2009-2013
FY 2009 Revised Rates Resource Stack - Detail Information

Amounts paid/projected by BPA for the resource - revenue requirement amounts:

	FY2007	FY2008	FY2009	FY2010	FY2011	FY2012	FY2013
GDP Inflation Factors Projections	1.000000	1.021026	1.042052	1.061396	1.082422	1.105130	1.126997
Program Case Revenue Requirement:							
Operation and Maintenance Charges	1,621,618	1,628,780	2,862,500	2,787,500	2,818,800	2,847,500	2,875,500
Transmission Charges	848,382	866,220	897,000	897,000	897,000	940,000	940,000
Debt Service Payments 4.20% Actual	11,619,490	11,582,810	11,571,060	11,566,000	11,563,000	11,559,430	11,546,060
Total Amounts Paid - Program Case Rates	14,089,490	14,077,810	15,330,560	15,250,500	15,278,800	15,346,930	15,361,560
7(b)(2) Case Revenue Requirement:							
Operation and Maintenance Charges	1,621,618	1,628,780	2,862,500	2,787,500	2,818,800	2,847,500	2,875,500
Transmission Charges	848,382	866,220	897,000	897,000	897,000	940,000	940,000
Total O&M	2,470,000	2,495,000	3,759,500	3,684,500	3,715,800	3,787,500	3,815,500
Debt Service Payments @ 4.25%	11,630,516	11,630,516	11,630,516	11,630,516	11,630,516	11,630,516	11,630,516
Total Amounts Paid - 7(b)(2) Case Rates	14,100,516	14,125,516	15,390,016	15,315,016	15,346,316	15,418,016	15,446,016
Average Annual Energy Output/@ 26.0MWh[2]	227,760	227,760	227,760	227,760	227,760	227,760	227,760
Cost per MWh	$61.91	$62.02	$67.57	$67.24	$67.38	$67.69	$67.82

Calculation of 7(b)(2) Debt Service - Average annual program case debt service FY2009-2013 = 11,561,110 = Program Case Debt Service

Assuming 30 yr term financing at interest rate of 4.20% in program case, PV of the payment
Stream of 30 annual payments @ interest rate of 4.20% = Principle Amount Financed FY 2009 = 195,148,632

Debt service payments for principle amount of $195,148,632, 30 annual payments, @ 4.25% = 11,630,516 = 7(b)(2) Case Debt Service

Interest rate of 4.25% is per the Financing Study prepared by the PFM Group, Appendix A to WP-07-FS-BPA-14 at Table A, page 4.

Note 2 - Firm average energy value (aMW) was obtained from Table 5 of the March 2007 BPA, 2007 Pacific Northwest Loads and Resources Study on page 23.

WP-07 Supplemental Rate Case
Section 7(b)(2) - Resource Stack - Updated Cost Projections for Idaho Falls Hydro Project
Purchase Power Contract
FY 2009 Revised Rates - Resource Stack

Idaho Falls Hydro Project - Revised Cost Projections:

7(b)(2) Case - Resource Stack Values:			FY 2009-$$	*FY 1980-$$
Annual Power Purchase Cost	162,030 MWh's @	$37.83	$6,129,979	$2,589,248
Placed in service			1982	1982
Average Annual Energy Output/@ 18.5.0MWh[3]			162,060.00	162,060.00
Average Hourly Energy aMW[3]			18.50	18.50
Cost per MWh			$37.83	$15.98

* Inflator conversion factor of 2.367475 was used to convert the resource cost data thats expressed in 2009 dollars to 1980 dollars. GDP - Deflator to convert 2009$$ to 1980$$ = 2.367475

Note 1 - Projected Contract Pricing MWH - $39.05 at contract cap rate, cost of power is expected to be at the cap during the rate test period. Only one month in FY 2007 was billed at a rate below the contract cap. Due to model escalation of O&M, the beginning FY 2009 amount was adjusted down to $37.83 so that the average escalated rate during the rate test period was less than the average Program Case rate during the rate test period.

Note 2 - Firm average energy value (aMW) was obtained from Table 5 of the March 2007 BPA, 2007 Pacific Northwest Loads and Resources Study on page 23.

BPA's Purchase Power Contract with Idaho Falls Power

	Projected Contract Price @ Contract Cap	GDP Deflator 2009$$ Conversion	2009$$ Real Pricing	Program Case Revenue Requirement Amounts @ 18.5 aMW	7(b)(2) Case Escalated Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2009	$39.05	1.000000	39.05	6,436,000	6,129,979	(306,021)
FY 2010	$39.05	1.023000	38.17	6,436,000	6,270,968	(165,032)
FY 2011	$39.05	1.048000	37.26	6,436,000	6,424,218	(11,782)
FY 2012	$39.05	1.075000	36.33	6,436,000	6,589,727	153,727
FY 2013	$39.05	1.101000	35.47	6,436,000	6,749,107	313,107
		Average	37.25537			(16,001)
Program Case Price Adjustment			0.57000			
7(b)(2) Case Pricing - 2009$$			37.83			

Historical Generation / Purchases from IFP

W/P Reference		Average Annual Energy - MWh	Capacity Factor @18 aMW
	2002	111,254	70.56%
	2003	113,443	71.95%
	2004	110,924	70.35%
	2005	119,433	75.74%
	2006	140,770	89.28%
	2007	132,415	83.98%
	6-Year Average	121,373	76.97%
	FY2006-2007 Average	136,593	86.63%

March 2007 BPA White Book Resource Values Table 5, page 23

Date in Service	1982
Capacity Peak MW	18
Firm energy aMW	19
Total Annual Energy @ 18	157,680
Total Annual Energy @ 19	166,440
LARIS average @ 18.5 aMW	162,060

Table A-4: Regional Independent Hydro Projects, PNW Loads and Resource Study, 2008 - 2009 Fiscal Years, [51] 2007 Final Supplemental Rate Case (Final) , 1937 Water Year, 7/17/2008
Projected annual hydro production for Idaho Falls Resource = 18.5 aMW 8,760 = 162,060

Table A-4: Regional Independent Hydro Projects, PNW Loads and Resource Study, 2009 - 2010 Fiscal Years, [51] 2007 Final Supplemental Rate Case (Final), 1937 Water Year, 7/17/2008
Projected annual hydro production for Idaho Falls Resource = 18.5 aMW 8,760 = 162,060

WP-07 Supplemental Rate Case
Section 7(b)(2) - Resource Stack - Updated Cost Projections for Nine Canyon Wind Project
FY 2009 Revised Rates Resource Stack - Detail Information
Operating Results / Projected Operating Budgets

7(b)(2) Resource Stack Amounts:

Portions Not Dedicated to Native Load:		**FY 2009$$**	**FY 1980$$**
Revenue Requirement Allocation to Non-Dedicated Portions =	48.00%	$7,578	$3,201
Share of total net annual generation (MWh)		118,459	118,459
Average energy per hour (aMW) / Name Plate rating times Capacity Factor		13.52	13.52
Share of name plate rating (MW)		46.03	46.03
GDP - Deflator to convert 2009$ to 1980$$ =	2.367475		
Cost of Power ($/MWh)		$63.97	$27.02

($ 000)

	OY_06 Actual	OY_07 Actual	OY_08 Actual	100% of Project OY_09 Budget 2009- $$$	Non-Dedicated Portion 48.00% of Project FY2009 Budget
Projected Costs of Operations[1]:					
Labor & Overheads	$677	$813	$1,330	$1,715	$823.2
Equipment / materials / Services	488	2,064	1,644	1,954	937.9
Insurance	118	130	117	341	163.7
Lease Payments	250	269	476	624	299.5
Control Area Reserves - Within Hour Balancing Charges[2]				783	375.6
Contingency / Fees	173	175		50	24.0
Other Costs	336	176	148	568	272.6
Generation Taxes	34	34	51	52	25.0
Subtotal Operating Costs	$2,076	$3,661	$3,766	$6,087	$2,921.4
Depreciation	3,798	3,697	3,993	7,222	3,466.4
Interest Financing - Costs	5,694	5,493	6,606	6,514	3,126.6
Gross Generation Costs	$11,568	$12,851	$14,365	$19,823	$9,514
Renewable Energy Production Incentive Credits (REPI)	(2,299)	(1,198)	(791)	(295)	(141.6)
Net Generation Costs	$9,269	$11,653	$13,574	$19,528	$9,373
Net Generation Costs per above	$9,269	$11,653	$13,574	$19,528	$9,373
Less Depreciation Expense	(3,798)	(3,697)	(3,993)	(7,222)	(3,466)
Capital requirements	(32)	221	203	150	72.0
Bond Retirement / Trustee Fees	3,285	3,423	4,361	3,774	1,811.4
Interest Income	(537)	(619)	(449)	(442)	(212.2)
Net Revenue Requirement	$8,187	$10,981	$13,696	$15,788	$7,578
Total Net Generation (MWh)	158,400	156,700	237,330	246,800	118,459
Cost of Power ($/MWh)	$51.69	$70.08	$57.71	$63.97	$63.97
Capacity Amount / Name plate	63.7MW	63.7MW	85.2	95.9MW	46.03 MW
Capacity Factor	28.39%	28.08%	31.81%	29.38%	29.38%

WP-07 Supplemental Rate Case
Section 7(b)(2) - Resource Stack - Updated Cost Projections for Nine Canyon Wind Project
FY 2009 Revised Rates Resource Stack - Detail Information
Operating Results / Projected Operating Budgets

Notes:

Note 1 - The actual operating results for operating years (OY) 2006, 2007, and 2008 along with the projected operating budget numbers for the resource were provided by Energy Northwest, the managing entity and operator of the wind project.

Note 2 - Starting in FY 2009 parties will have to self provide or purchase wind integration - within-hour balancing reserves for wind resources. This cost was added to the operating cost budget by BPA to arrive at a reasonable operating cost for this resource in the resource stack. The charges are based on BPA's 2009 Wind Integration Rate Case Revised Proposal, Attachment 1 to Settlement Agreement ACS-09, page 1, where the rate is $0.68 per kilowatt per month with the rate based on the installed capacity of the wind plant. Mathematically this is expressed:
Installed capacity = 95.9MW * 1,000 = 95,900KW * $0.68 = $65,212 per month, times 12 months = $782,544 for the year.

Note 3 The Nine Canyon Resource is part of this utility's resource mix, it is not treated as a firm resource, they have not entered into specific sales contracts for the sale of specific wind energy from this resource at this time. Utility is not sure how this resource will be used during the rate test period.

Energy Northwest 95.9 MW Nine Canyon Wind Power Project Allocations - Phases 1, 2, and 3

Nine Purchasers	Phase 1 MW Share	Phase 2 MW Share	Phase 3 MW Share	Total MW Share	% total	Resource Dedicated to native Load?
Benton County PUD No. 1	3.00	0.00	9.00	9.00	9.38%	Yes[1]
Chelan County PUD No. 1	6.01	1.95	7.96	7.96	8.30%	Yes
Cowlitz Co PUD	2.00	0.00	2.00	2.00	2.09%	Yes
Douglas County PUD No. 1	3.01	6.80	9.81	9.81	10.23%	Quasi[2]
Franklin PUD No. 1	2.01	0.00	**10.06**	**10.06**	**10.49%**	**NO**
Grays Harbor PUD No. 1	**6.01**	**1.95**	**20.04**	**20.04**	**20.90%**	**NO**
Lewis County PUD No. 1	1.00	0.00	6.06	6.06	6.32%	Yes
Okanogan County PUD No. 1	**12.03**	**3.90**	**15.93**	**15.93**	**16.61%**	**NO**
Grant County PUD No. 2	12.03	0.00	12.03	12.03	12.54%	Quasi[2]
Mason County PUD No. 3	1.00	1.00	3.01	3.01	3.14%	Yes
Total	48.10	15.60	95.90	95.90	100.00%	
Non-Dedicated Portion				**46.03**	**48.00%**	

Notes:

Note 1 - Gloria Bender from Benton PUD informed BPA that all of its wind purchases will be used to meet their Tier 2 loads during FY2012-2029.

Note 2 - Resource is part of the utilities resource mix, it is not treated as a firm resource, they have not entered into specific sales contracts for the sale of specific wind energy from this resource at this time. Utility is not sure how this resource will be used during the rate test period.

Note 3 - Confirmed that the resource was not dedicated to this utilities native load through their BPA Account Executive.

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 SupplementalRate Case
Section 7(b)(2) Resource Stack Supporting Documentation
FY 2009 Revised Rates Resource Stack - Detail Information

7(b)(2) Case - Resource Stack Values:	**FY2009-$$**	**FY1980-$$***
Total Operating Costs - FY 2009 Non-dedicated COU & Marketer Projection = 17.7aMW *$16.4144/MWh*8,760 hour /year	2,545,086	1,075,021
Cost per MWh	$16.41	$6.93
Capital Investment - Projected Net Utility Plant FY 2007 per Financial Statement	$189,610,161	NA
Life	70-100 years	70-100 years
Placed in service	1959	1959
Non-dedicated COU & Marketer average hourly energy (aMW) five-year average FY2009-2013	17.7	17.7
Average Annual Energy Output/@ 17.7MWh	155,052	155,052

* Deflator conversion factor of 2.367475, was used to convert the resource cost data that is expressed in 2009 dollars to 1980 dollars. 2.367475

	2002	2003	2004	2005	2006	2007	2008	2009
GDP Inflation Factors Projections				1.017	1.017	1.021	1.021026	1.021026
	(in whole dollars) Financial Statement Information			BPA Analyst Projected Operating Budget	**Grant's[6] Projected Operating Budget**	BPA Analyst Projected Operating Budget	Projected Operating Budget	Projected Operating Budget
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Operating Revenues	32,064,057	30,810,541	30,707,299	34,600,000	44,000,000	46,000,000	46,967,196	47,954,728
Operating Expenses - See Notes 1, 2, and 4 below:								
Generation	11,636,471	10,122,746	10,402,512	10,579,355	7,243,491	7,395,604	7,551,104	7,709,874
Transmission	889,319	850,426	838,216	852,466	795,871	812,584	829,670	847,114
Administrative and General	6,897,861	6,570,905	6,106,684	6,210,498	10,823,737	11,051,035	11,283,395	11,520,639
Maintenance Expenses					5,653,207	5,771,924	5,893,285	6,017,197
Depreciation Expenses	4,613,571	3,681,788	5,078,184	5,157,659	5,334,210	5,513,763	5,696,367	5,882,807
Taxes	856,948	783,116	801,631	815,259	850,000	867,850	886,097	904,728
Other Operating Costs				1,240,681				
Total Operating Expenses *	24,894,170	22,008,981	23,227,227	24,855,917	30,700,516	31,412,761	32,139,918	32,882,360
Net Operating Income	7,169,887	8,801,560	7,480,072	9,744,083	13,299,484	14,587,239	14,827,278	15,072,369

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 SupplementalRate Case
Section 7(b)(2) Resource Stack Supporting Documentation
FY 2009 Revised Rates Resource Stack - Detail Information

Non Operating Revenues and (Expenses)									
Interest Income (Expense)/Gains on Debt Retirements	*	967,727	451,766	338,167	300,000	1,670,598	1,500,000	1,500,000	1,500,000
Interest on Proposed New Debt	*					(3,287,457)	(3,300,000)	(3,300,000)	(3,300,000)
Interest on Long-Term Debt - See Note 3	*	(8,253,381)	(8,029,995)	(7,575,817)	(9,050,531)	(8,792,613)	(11,850,662)	(11,852,968)	(11,847,774)
Amortization of Debt Expense and Discounts		(614,378)	(695,559)	(694,445)	(693,000)	(691,500)	(700,000)	(700,000)	(700,000)
Total Non Operating Expenses		(7,900,032)	(8,273,788)	(7,932,095)	(9,443,531)	(11,100,972)	(14,350,662)	(14,352,968)	(14,347,774)
Excess (Shortfall) of Revenues Over Cost of Services		(730,145)	527,772	(452,023)	300,552	2,198,512	236,577	474,310	724,595
Operating Costs Before Adjustments		32,179,824	29,587,210	30,464,877	33,606,448	41,109,988	45,063,423	45,792,886	46,530,133
(* Sum of numbers asterisks)									

Schedule of Power Costs:	(in whole dollars) Financial Statement Information **2002**	**2003**	**2004**	BPA Analyst Projected Operating Budget **2005**	**Grant's Projected Operating Budget 2006**	BPA Analyst Projected Operating Budget **2007**	BPA Analyst Projected Operating Budget **2008**	BPA Analyst Projected Operating Budget **2009**
Operating Costs Before Adjustments - sum of *	32,179,824	29,587,210	30,464,877	33,606,448	41,109,988	45,063,423	45,792,886	46,530,133
Budget/Operating Cost Adjustments:								
Less Extraordinary maintenance paid by Reserve Funds	(76,008)	(68,630)	0	0	0	0	0	0
Less Depreciation Expense	(4,613,571)	(3,681,788)	(5,078,184)	(5,157,659)	(5,334,210)	(5,513,763)	(5,696,367)	(5,882,807)
Less 15% of prior year second series debt installments	(1,985,010)	(1,926,646)	(1,952,249)	(1,900,317)	(2,079,116)	(2,899,511)	(2,916,392)	(2,917,500)
Plus (less) exclusion of interest on special funds	39,934	(54,716)	(146,826)	(149,322)		(152,458)	(155,663)	(158,936)
Plus capitalized interest	45,928	0	268,747	233,930	0	241,951	247,032	252,226
Plus Principal and sinking fund payments on debt - See Note 4 below.	4,545,000	4,985,000	5,195,000	5,195,000	7,250,000	7,350,000	7,350,000	7,350,000
Plus 15% of interest and sinking fund installments	1,926,646	1,952,249	1,955,935	2,171,919	2,899,511	2,916,392	2,917,500	2,917,500
Bond issuance costs	1,314	17,861	0	0		0	0	0
Net Costs Chargeable to Power Purchasers	32,064,057	30,810,540	30,707,300	33,999,999	43,846,173	47,006,035	47,538,995	48,090,617
Projected Owners Operating Budget escalated for inflation - whole dollars				$33,999,999	$43,846,173	$47,006,035	$47,538,995	$48,090,617
Average Firm Energy Output (PNW L&R Study #30) (334.45MW) times the number of hours in a year (8760)				2,929,782	2,929,782	2,929,782	2,929,782	2,929,782
Projected Project Cost per MWh using Project Owners Debt Service				**$11.6050**	**$14.9657**	**$16.0442**	**$16.2261**	**$16.4144**

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs

BPA's Wholesale Power 2007 SupplementalRate Case

Section 7(b)(2) Resource Stack Supporting Documentation

FY 2009 Revised Rates Resource Stack - Detail Information

Selected Balance Sheet Items - Priest Rapids Hydroelectric Project:

(in whole dollars)

	2002	2003	2004	2005	2006	2007	2008	2009
Electric Plant Gross (Dam placed in service 1970)	$248,319,424	$250,995,893	$257,882,972	266,710,518	275,688,132	284,818,366	294,140,335	303,658,307
Land and land rights	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576
Construction work in progress - See Note 3	4,381,441	10,183,113	8,827,546	8,977,614	9,130,234	9,321,969	9,517,972	9,718,097
Accum. Deprec. & Amortization (15-95 year lives)	(107,042,152)	(110,725,130)	(115,853,195)	(121,010,854)	(126,345,065)	(131,858,827)	(137,555,195)	(143,438,001)
Net Electric Plant (Note 3 of 2003 & 2004 F.S.)	148,245,289	153,040,452	153,443,899	157,263,854	161,059,877	164,868,083	168,689,688	172,524,979
Deferred relicensing costs	15,969,761	21,479,506	25,926,488					
Unamortized debt expense	1,747,505	2,084,600	1,853,557					
Other Deferred Charges and other assets	9,306	0	0					
Total Non Current Assets	165,971,861	176,604,558	181,223,944					
Restricted Assets Current	30,208,013	42,056,984	32,527,571					
Current and Accrued Assets	16,200,038	7,951,490	8,182,286					
Total Current Assets	46,408,051	50,008,474	40,709,857					
Total Assets	$212,379,912	$226,613,032	$221,933,801					
Long-Term Debt-net of discounts	$145,591,449	$172,146,382	$167,414,785					
Current portion of long-term debt	4,545,000	4,985,000	5,195,000					
Current & Accrued Liabilities	22,860,256	9,570,671	9,865,060					
Other Liabilities								
Total Liabilities	172,996,705	186,702,053	182,474,845					
Retained Earnings - restricted for debt service	6,338,804	6,940,349	7,178,763					
Retained Earnings - restricted other	6,000,000	6,000,000	0					
Retained Earnings - unrestricted	27,044,403	26,970,630	32,280,193					
Total Liabilities & Retained Earnings	$212,379,912	$226,613,032	$221,933,801					

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs

BPA's Wholesale Power 2007 SupplementalRate Case

Section 7(b)(2) Resource Stack Supporting Documentation

FY 2009 Revised Rates Resource Stack - Detail Information

Notes:

1. The financial information for the years 2002, 2003, and 2004 was from Grant County PUD No. 2's audited financial statements, primarily the audited financial statements on the individual developments (enterprise funds), and the Schedules of Power Costs and Allocation to Power Purchasers.

2. The operating cost projections for the years 2005-2007 were based on the 2004 and prior years' audited reports as adjusted for the GNP Price Deflator Inflation Projection obtained from DRI. Specific projections for depreciation expense and debt service were based on the 2004 audited financial statement's notes and other supplementary information.

3. Debt Service Information

The actual interest (a) and principal (b) on the Priest Rapids Bonds for the years 2002-2004 was taken from the Statement of Cash Flows. The projected interest (a) and projected principal (b) for 2005-2007 on the Priest Rapids Revenue Bonds was obtained from Note 5 of the 2004 financial statements (p103), Scheduled debt service requirements. A portion of the information for 2002-2004 was from the Schedules of Power Costs Chargeable to Power Purchasers. The projections for capitalized interest expense for 2005-2007 was computed using an assumed interest rate of 2.65% applied to the balance of construction work in progress at the beginning of the year.

	2002	2003	2004	2005	2006	2007	2008	2009
Actual/Projected Interest on Priest Rapids Bonds (a)	8,052,724	7,511,045	7,683,777	9,284,461	9,030,520	8,792,613	8,800,000	8,800,000
Less Capitalized interest expenses	(45,928)	0	(268,747)	(233,930)	(237,907)	(241,951)	(247,032)	(252,226)
Adjustment in interest expense	246,585	518,950	160,787	0	0	0	0	0
Interest on proposed new debt (a)					3,287,457	3,300,000	3,300,000	3,300,000
Total Interest Expense per operating statement projections	8,253,381	8,029,995	7,575,817	9,050,531	12,080,070	11,850,662	11,852,968	11,847,774
Actual/Projected Principal payments on Priest Rapids Bonds (b)	4,270,000	4,545,000	4,985,000	5,195,000	7,250,000	7,350,000	7,350,000	7,350,000
Total Debt Service (a) + (b)	12,322,724	12,056,045	12,668,777	14,479,461	19,567,977	19,442,613	19,450,000	19,450,000
15% of Debt Service Requirements			1,900,317	2,171,919	2,899,511	2,916,392	2,917,500	2,917,500

4. Under the Power Sales Contracts (See Note 1, accounting policies, revenue recognition), the power purchasers of the project pay all expenses and costs associated with producing and delivering the power, plus 115% of their share of the amounts required for debt service payments. Depreciation, extraordinary maintenance, and other charges are paid by the Reserve and Replacement Fund, Supplemental Repair and Renewal Fund, and Construction Fund and are not considered costs of producing and delivering power for this purpose.

5. Projection of depreciation expense is based on a 2% recovery rate applied to the plant in service balance at the beginning of the year. Electric plant financial information can be found at Note 3 of the Priest Rapids Project's financial segment information (pg. 99 of 2004 F.S.).

6. BPA sent a data request to Grant County PUD #2 dated 5/11/2005 for the projected operating costs of the Priest Rapids Hydroelectric project for the years 2006-2013. Grant County PUD#2 did not respond to the data request. BPA sent a projection of operating costs to Grant County PUD#2 on September 19, 2005, and asked it to please review and make corrections to the projections. Grant County PUD #2 responded in an email on 9/28/05 that its projected operating costs for Priest Rapids project for FY2006 were $43.8 million dollars per year. The projected budget numbers received from Grant for FY2006 are reflected in the spreadsheet.

Grant's Priest Rapids Allocation for 2007-2013
Remainder of Data for 2009-2013 is BPA's Table A-20 Priest Rapids Allocation
PNW Loads and Resource Study
2007 - 2013 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case for 2007- 2008 / 2007 Supplemental 2009 - 2013

Priest Rapids Energy in Megawatts		2007	2008	2009	2010	2011	2012	2013
Priest Rapids Dam, Project Owner = Grant County PUD, FERC License Exp. 10/31/2005, New Purchaser Agreements became effective 11/01/2005.								
Priest Rapids								
30 AVWP - Avista Share		11.5	11.5	12.0	14.0	13.0	13.0	13.0
31 COPD - Cowlitz County PUD Share		5.3	5.3	5.6	8.8	9.9	9.9	9.9
32 CWPC - Clear Water PUD Share	**	0.4	0.4	0.4	0.4	0.4	0.4	0.4
33 EWEB - Eugene Water & Electric Share		3.2	3.2	3.4	4.0	3.7	3.6	3.6
34 FGRV - Forest Grove Share		1.2	1.2	1.3	1.5	1.6	1.6	1.6
35 FREC - Fall River Electric Coop. Share	**	0.5	0.5	0.5	0.5	0.5	0.5	0.5
36 GCPD - Grant County PUD Share		215.8	216.2	229.0	202.0	213.0	215.0	216.0
37 ICLP - Idaho City Light PUD Share	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
38 KITT - Kittitas County PUD Share		1.0	1.0	1.0	0.7	0.5	0.5	0.5
39 KOOT - Kootenai Share	**	0.7	0.7	0.7	0.7	0.7	0.7	0.7
40 LREC - Lost River Electric Cooperative Share	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
41 LVE - Lower Valley Electric Coop. Share	**	0.9	0.9	0.9	0.9	0.9	0.9	0.9
42 MCMN - McMinnville Share		1.2	1.2	1.3	1.5	1.6	1.6	1.6
43 MTFR - Milton Freewater Share		1.2	1.2	1.3	1.5	1.6	1.6	1.6
44 NLEC - Northern Lights Electric Coop. Share	**	0.6	0.6	0.6	0.6	0.6	0.6	0.6
45 PGE - Portland General Electric Share		26.2	26.3	28.0	33.0	30.0	29.0	29.0
46 PPL - Pacific Power and Light Share		26.2	26.3	28.0	33.0	30.0	29.0	29.0
47 PSE - Puget Sound Energy Share		15.1	15.1	16.0	19.0	17.0	17.0	17.0
48 RREC - Raft River Electric Coop. Share	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
49 SCL - Seattle City Light Share		1.9	1.9	2.0	14.0	16.7	16.0	16.0
50 SLEC -Salmon River Electric Coop. Share	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
51 TPU - Tacoma Public Utilities Share		14.2	14.2	15.0	18.0	16.7	16.0	16.0
52 UNEC - United Electric Coop. Share	**	0.2	0.2	0.3	0.3	0.3	0.3	0.3
53 UNKMKT - Unknown Market Purchaser Share	**	22.8	22.9	22.0	14.0	11.0	11.0	11.0
54 Priest Rapids After Encroachment		350.9	351.5	369.8	368.9	370.2	368.6	369.7
COUs not Dedicated to Rgional Loads and Market Purchaser Allocations - **		26.6	26.7	25.9	17.9	14.9	14.9	14.9
Other Power Allocations		324.3	324.8	343.9	351.0	355.4	353.8	354.8
TOTAL		350.9	351.5	369.8	368.9	370.2	368.6	369.7

Non-dedicated COUs and
Market Purchaser Energy -
Seven Year Average Allocation FY2007-2013 = 20.2 Percent of Total Generation = 5.56%
Seven Year Total Power Generation Average FY2009-FY2013 = 364.2
Non-dedicated COUs and
Market Purchaser Energy -
Five Year Average Allocation FY2009-2013 17.7 Percent of Total Generation = 4.78%
Five Year Total Power Generation Average FY2009-FY2013 = 369.4

Priest Rapids Allocation Percentages	2007	2008	2009	2010	2011	2012	2013
COUs not Dedicated to Rgional Loads and Market Purchaser Allocations - **	7.59%	7.59%	7.00%	4.84%	4.01%	4.03%	4.02%
Other Power Allocations	92.41%	92.41%	93.00%	95.16%	95.99%	95.97%	95.98%
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Non-dedicated COUs and
Market Purchaser Energy -
Seven Year Average Allocation FY2007-2013 **5.56%**
Non-dedicated COUs and
Market Purchaser Energy -
Five Year Average Allocation FY2009-2013 **4.78%**

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 SupplementalRate Case
Section 7(b)(2) Resource Stack Supporting Documentation
FY 2009 Revised Rates Resource Stack - Detail Information

7(b)(2) Case - Resource Stack Values:	**FY2009-$$**	**FY1980-$$***
Total O&M - FY 2009 Non-dedicated COU & Marketer Projection = 10.0aMW *$15.7037/MWh*8,760 hour /year	1,375,644	581,060
Cost per MWh	$15.70	$6.63
Capital Investment - Projected Net Utility Plant FY 2007 per Financial Statement	362,467,399	NA
Life	70-100 years	70-100 years
Placed in service	1963	1963
Non-dedicated COU & Marketer average hourly energy (aMW) five-year average FY2009-2013	10.0	10.0
Average Annual Energy Output/@ 10.0MWh	87,600	87,600

2.367475

* Deflator conversion factor of 2.367475, was used to convert the resource cost data that is expressed in 2009 dollars to 1980 dollars.

(in whole dollars)

		Financial Statement Information 2002	2003	2004	Projected Operating Budget 2005	Projected Operating Budget 2006	Projected Operating Budget 2007	Projected Operating Budget 2008	Projected Operating Budget 2009
GDP Inflation Factors Projections					1.017	1.017	1.021	1.021026	1.021026
Operating Revenues		$39,654,100	$37,623,004	$30,184,495	$32,000,000	$35,500,000	$36,000,000	$36,756,936	$37,529,787
Operating Expenses - See Notes 1, 2, and 3 below:									
Generation		12,623,551	11,099,675	10,388,384	10,564,987	10,744,591	10,970,228	$11,200,888	$11,436,398
Transmission		977,237	948,778	969,101	985,576	1,002,331	1,023,379	$1,044,897	$1,066,867
Administrative and General		6,759,515	6,451,674	5,423,216	5,515,411	5,609,173	5,726,965	$5,847,380	$5,970,327
Depreciation Expenses		4,924,752	5,031,141	5,152,363	5,440,350	6,505,942	7,589,649	8,691,778	9,817,052
Taxes		852,347	764,649	803,820	817,485	831,382	848,841	$866,689	$884,912
Other Operating Expenses						3,804,777	4,646,241	$4,743,933	$4,843,679
Total Operating Expenses	*	26,137,402	24,295,917	22,736,884	23,323,808	28,498,196	30,805,303	32,395,565	34,019,235
Net Operating Income		13,516,698	13,327,087	7,447,611	8,676,192	7,001,804	5,194,697	4,361,371	3,510,552

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 SupplementalRate Case
Section 7(b)(2) Resource Stack Supporting Documentation
FY 2009 Revised Rates Resource Stack - Detail Information

Non Operating Revenues and (Expenses)									
* Interest Income (Expense)/Gains on Debt Retirements	*	958,126	476,575	219,143	180,000	180,000	180,000	180,000	180,000
* Interest on Long-Term Debt - See Note 2	*	(7,177,896)	(7,838,985)	(6,275,562)	(7,712,258)	(7,460,490)	(7,188,412)	(7,157,746)	(7,126,396)
Amortization of Debt Expense and Discounts		(713,449)	(806,562)	(749,297)	(747,000)	(745,000)	(743,000)	(743,000)	(743,000)
Total Non Operating Expenses		(6,933,219)	(8,168,972)	(6,805,716)	(8,279,258)	(8,025,490)	(7,751,412)	(7,720,746)	(7,689,396)
Excess (Shortfall) of Revenues Over Cost of Services		$6,583,479	$5,158,115	$641,895	$396,933	($1,023,685)	($2,556,716)	($3,359,375)	($4,178,844)
Operating Costs Before Adjustments		$32,357,172	$31,658,327	$28,793,303	$30,856,067	$35,778,685	$37,813,716	$39,373,311	$40,965,631
(* Sum of numbers asterisks)									

Schedule of Power Costs:

	(in whole dollars) Financial Statement Information			Projected Operating Budget	Projected Operating Budget	Projected Operating Budget	Projected Operating Budget	Projected Operating Budget
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Operating Costs Before Adjustments (from prior page)	$32,357,172	$31,658,327	$28,793,303	$30,856,067	$35,778,685	$37,813,716	$39,373,311	$40,965,631
Budget/Operating Cost Adjustments - See Note 3 below:								
Less Extraordinary maintenance paid by Reserve Funds	(255,008)	(90,831)	0	0	0	0	0	0
Less Depreciation Expense - See Note 4	(4,924,752)	(5,031,141)	(5,152,363)	(5,440,350)	(6,505,942)	(7,589,649)	(8,691,778)	(9,817,052)
Less 15% of prior year second series debt installments	(1,711,094)	(1,675,494)	(1,892,772)	(1,908,116)	(2,145,625)	(2,145,960)	(2,378,060)	(2,347,310)
Plus (less) exclusion of interest on special funds	(56,168)	(108,416)	(115,046)	(117,002)	(118,991)	(121,490)	(124,041)	(126,646)
Plus capitalized interest	487,658	299,965	1,437,425	1,411,909	1,435,911	1,460,322	1,490,988	1,522,338
Plus principal and sinking fund payments on debt - See Note 4	10,955,000	9,924,804	5,180,000	5,180,000	5,410,000	7,205,000	7,000,000	7,000,000
Plus 15% of current year's interest and sinking fund installments	2,793,083	2,614,184	1,933,948	2,145,625	2,145,960	2,378,060	2,347,310	2,347,310
Bond issuance costs	8,209	31,606	0	0	0	0	0	0
Net Costs Chargeable to Power Purchasers -	$39,654,100	$37,623,004	$30,184,495	$32,128,132	$35,999,999	$38,999,999	$39,017,730	$39,544,271
Projected Operating Cost Projections				$32,128,132	$35,999,999	$38,999,999	$39,017,730	$39,544,271
Average Firm Energy Output (PNW L&R Study #30) (287.46MW) times the number of hours in a year (8760)				2,518,150	2,518,150	2,518,150	2,518,150	2,518,150
Projected Project Cost per MWh				**$12.7586**	**$14.2962**	**$15.4876**	**$15.4946**	**$15.7037**

Selected Balance Sheet Items - Wanapum Hydroelectric Project:

	2002	2003	2004	2005	2006	2007	2008	2009
Electric Plant Gross (Dam placed in service 1963)	258,738,862	$263,178,360	$272,017,524	325,297,099	379,482,427	434,588,905	490,852,620	548,299,335
Land and land rights	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695
Construction work in progress	9,865,278	21,230,005	53,279,575	54,185,328	55,106,478	56,263,714	57,446,715	58,654,590
Accumulated Deprec. & Amortization (15-95 year lives)	(100,896,839)	(105,929,169)	(111,130,577)	(116,570,927)	(123,076,869)	(130,666,518)	(139,358,296)	(149,175,348)
Net Electric Plant (See Note 4)	184,148,996	194,920,891	230,608,217	279,353,194	327,953,731	376,627,797	425,382,734	474,220,271
Deferred relicensing costs	15,969,794	21,492,288	25,954,022					
Unamortized debt expense	1,308,608	2,115,744	1,886,648					
Other Deferred Charges and other assets	9,306	0	33,566					
Total Non Current Assets	201,436,704	218,528,923	258,482,453					
Restricted Assets Current	18,796,718	30,027,733	27,831,707					
Current and Accrued Assets	18,027,531	17,559,743	8,415,820					
Total Current Assets	36,824,249	47,587,476	36,247,527					
Total Assets	$238,260,953	$266,116,399	$294,729,980					
Long-term debt-net of discounts	$130,986,005	$175,234,571	$170,574,771					
Current portion of long-term debt	11,025,000	4,905,000	5,180,000					
Current & accrued liabilities	24,983,524	9,156,639	40,633,275					
Other liabilities								
Total Liabilities	166,994,529	189,296,210	216,388,046					
Retained Earnings - restricted for debt service	7,654,084	6,797,772	7,107,257					
Retained Earnings - restricted other	0	0	0					
Retained Earnings - unrestricted	63,612,340	70,022,417	71,234,677					
Total Liabilities & Retained Earnings	$238,260,953	$266,116,399	$294,729,980					

Notes:

1. The financial information for the years 2002, 2003, and 2004 was from Grant County PUD No. 2's audited financials, primarily the audited financial statements on the individual developments (enterprise funds), and the Schedules of Power Costs and Allocation to Power Purchasers.

2. The operating cost projections for the years 2005-2007 were based on the 2004 and prior years audited reports as adjusted for the GNP Price Deflator Inflation Projection obtained from DRI. Specific projections for depreciation expense and debt service were based on the 2004 audited financial statement' notes and other supplementary information. The operating cost projections for FY2008-2009 were escalated from the prior year's analysis.

3. Debt Service Information
The actual interest (a) and principle (b) on the Wanapum Bonds for the years 2002-2004 was taken from the Statement of Cash Flows. The projected interest (a) and projected principal (b) for 2005-2007 on the Wanapum Revenue Bonds was obtained from Note 5 of the 2004 financial statements (p134), Scheduled debt service requirements. A portion of the information for 2002-2004 was from the Schedules of Power Costs Chargeable to Power Purchasers. The projections for capitalized interest expense for 2005-2007 was computed using an assumed interest rate of 2.65% applied to the balance of construction work in progress at the beginning of the year.

	2002	2003	2004	2005	2006	2007	2008	2009
Actual/Projected Interest on Wanapum Bonds (a)	7,546,528	7,166,547	7,815,774	9,124,167	8,896,401	8,648,734	8,648,734	8,648,734
Less Capitalized interest expenses	(487,657)	(299,965)	(1,437,425)	(1,411,909)	(1,435,911)	(1,460,322)	(1,490,988)	(1,522,338)
Adjustment in interest expense	119,025	972,403	(102,787)					
Total Interest Expense per operating statement	7,177,896	7,838,985	6,275,562	7,712,258	7,460,490	7,188,412	7,157,746	7,126,396
Actual/Projected Principal payments on Priest Rapids Bonds (b)	11,570,000	19,025,000	4,905,000	5,180,000	5,410,000	7,205,000	7,000,000	7,000,000
Total Debt Service (a) + (b)	19,116,528	26,191,547	12,720,774	14,304,167	14,306,401	15,853,734	15,648,734	15,648,734
15% of Current year's debt service requirement	2,867,479	3,928,732	1,908,116	2,145,625	2,145,960	2,378,060	2,347,310	2,347,310

4. Under the Power Sales Contracts (See Note 1, accounting policies, revenue recognition), the power purchasers of the project pay all expenses and costs associated with producing and delivering the power, plus 115% of their share of the amounts required for debt service payments. Depreciation, extraordinary maintenance, and other charges are paid by the Reserve and Replacement Fund, Supplemental Repair and Renewal Fund, and Construction Fund and are not considered costs of producing and delivering power for this purpose.

5. Projection of depreciation expense is based on a 2% recovery rate of applied to the plant in service balance at the beginning of the year. Electric plant financial information can be found at Note 3 of the Wanapum Project's financial segment information (p129 of 2004 F.S.).

6. BPA sent a data request to Grant County PUD #2 dated 5/11/2005 for the projected operating costs of the Wanapum Hydroelectric project for the years 2006-2013. Grant County PUD#2 did not respond to the data request. BPA sent a projection of operating costs to Grant County PUD#2 on September 19, 2005, and asked it to please review and make corrections to the projections. Grant County PUD #2 did not choose to comment on the projections of operating costs for the Wanapum Hydroelectric project. In estimating the projected operating costs for the Wanapum project the costs trends that were present in the Priest Rapids Hydroelectic project for which Grant County PUD #2 did comment upon, were taken into account in projecting the operating costs for the Wanapum project.

Wanapum Allocation for 2007 - 2013
PNW Loads and Resource Study
2007 - 2013 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case for 2007- 2008 / 2007 Supplemental 2009 - 2013

Wanapum Energy in Megawatts		2007	2008	2009	2010	2011	2012	2013
Wanapum Dam, Project Owner = Grant County PUD, FERC License Exp. 10/31/2009, Existing Purchaser Agreement Expires 10/31/2009, New Contracts Provisions become effective 11/01/09								
Wanapum								
3 AVWP - Avista Share		29.4	29.5	26.0	16.0	11.0	11.0	11.0
4 COPD - Cowlitz County PUD Share		9.7	9.7	8.6	8.6	8.6	8.6	8.6
5 CWPC - Clear Water PUD Share	**	0.0	0.0	0.0	0.3	0.4	0.4	0.4
6 EWEB - Eugene Water & Electric Share		8.3	8.3	7.3	4.6	3.2	3.1	3.1
7 FGRV - Forest Grove Share		2.5	2.5	2.2	1.6	1.3	1.3	1.3
8 FREC - Fall River Electric Coop. Share	**	0.0	0.0	0.0	0.3	0.4	0.4	0.4
9 GCPD - Grant County PUD Share		131.0	131.2	117.0	154.0	184.0	186.0	187.0
10 ICLP - Idaho City Light PUD Share	**	0.0	0.0	0.0	0.1	0.1	0.1	0.1
11 KITT - Kittitas County PUD Share		0.0	0.0	0.0	0.3	0.4	0.4	0.4
12 KOOT - Kootenai Share	**	0.0	0.0	0.0	0.6	0.7	0.7	0.7
13 LREC - Lost River Electric Cooperative Share	**	0.0	0.0	0.0	0.1	0.1	0.1	0.1
14 LVE - Lower Valley Electric Coop. Share	**	0.0	0.0	0.0	0.6	0.8	0.8	0.8
15 MCMN - McMinnville Share		2.5	2.5	2.2	1.6	1.3	1.3	1.3
16 MTFR - Milton Freewater Share		2.5	2.5	2.2	1.6	1.3	1.3	1.3
17 NLEC - Northern Lights Electric Coop. Share	**	0.0	0.0	0.0	0.4	0.5	0.5	0.5
18 PGE - Portland General Electric Share		67.1	67.2	60.0	37.0	26.0	25.0	25.0
19 PPL - Pacific Power and Light Share		67.1	67.2	60.0	37.0	26.0	25.0	25.0
20 PSE - Puget Sound Energy Share		38.8	38.8	34.0	22.0	15.0	15.0	14.0
21 RREC - Raft River Electric Coop. Share	**	0.0	0.0	0.0	0.1	0.1	0.1	0.1
22 SCL - Seattle City Light Share		0.0	0.0	0.0	12.0	14.0	14.0	14.0
23 SLEC -Salmon River Electric Coop. Share	**	0.0	0.0	0.0	0.1	0.1	0.1	0.1
24 TPU - Tacoma Public Utilities Share		0.0	0.0	0.0	12.0	14.0	14.0	14.0
25 UNEC - United Electric Coop. Share	**	0.0	0.0	0.0	0.3	0.3	0.3	0.3
26 UNKMKT - Unknown Market Purchaser Share	**	0.0	0.0	0.0	7.2	9.6	9.6	9.6
27 Wanapum After Encroachment		358.9	359.5	319.5	318.5	319.3	319.2	319.2
COUs not Dedicated to Rgional Loads and Market Purchaser Allocations - **		0.0	0.0	0.0	10.2	13.2	13.2	13.2
Other Power Allocations		358.9	359.5	319.5	308.3	306.1	306.0	306.0
TOTAL		358.9	359.5	319.5	318.5	319.3	319.2	319.2

Non-dedicated COUs and
Market Purchaser Energy -
Five Year Average Allocation FY2009-2013 10.0 aMW Percent of Total Generation = 3.12%
Five Year Total Power Generation Average FY2009-FY2013 319.1 aMW

Wanapum Percentage Share		2007	2008	2009	2010	2011	2012	2013
COUs not Dedicated to Regional Loads and Market Purchaser Allocations - **		0.00%	0.00%	0.00%	3.20%	4.13%	4.14%	4.14%
Other Power Allocations		100.00%	100.00%	100.00%	96.80%	95.87%	95.86%	95.86%
TOTAL		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Non-dedicated COUs and
Market Purchaser Energy -
Five Year Average Allocation FY2009-2013 **3.12%**

Note - The non-dedicated COU portions of Wanapum were not available to serve loads during FY 2007-2008. This resource was not included in the FY2007-2008 Lookback resource stack because it was not available during FY2007-2008.

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack - Wauna CoGen Resource for FY 2009-2013
Purchase Power Contract
FY 2009 Revised Rates Resource Stack

Wauna CoGeneration Resource - Revised Cost Projections:

7(b)(2) Case - Resource Stack Values:	FY2009-$$	*FY1980-$$
Annual Power Purchase Cost - See Note 1	$11,153,933	4,711,320
Placed in service	1996	1996
Average Annual Energy Output/@ 23.0MWh[2]	201,480	201,480
Cost per MWh	$55.36	$23.38

* Inflator conversion factor of 2.367475 was used to convert the resource cost data that is expressed in 2009 dollars to 1980 dollars. 2.367475

Note 1 - After a resource is chosen by the rates model, its annual costs (stated in 1980 "real dollars") are inflated by the GDP deflator values contained in the model to the nominal dollars of the year the resource is selected. These costs are escalated for each of the remaining years of the rate test period. The contract price was adjusted to ensure that the cost for this resource in the 7(b)(2) Case does not exceed the costs that were included for the Program Case revenue requirement.

Note 2 - Firm average energy value (aMW) was obtained from Table 5 of the March 2007 BPA, 2007 Pacific Northwest Loads and Resources Study on page 23.

BPA's Purchase Power Contract with Western Generation Agency - Wauna Cogeneration Project - Contract Pricing Schedule

	Contract Price - Nominal Pricing	GDP Deflator 2007$$ Conversion	2007$$ Real Pricing	Program Case Revenue Requirement Amounts @ 23 aMW	7(b)(2) Case Escalated Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2009	58.14	1.000000	58.14	11,249,900	11,153,933	(95,967)
FY 2010	59.21	1.023000	57.88	11,462,700	11,410,473	(52,227)
FY 2011	60.33	1.048000	57.57	11,732,500	11,689,322	(43,178)
FY 2012	61.51	1.075000	57.22	11,922,500	11,990,478	67,978
FY 2013	62.75	1.101000	56.99	12,169,500	12,280,480	110,980
		Average	57.5595657			(12,415)
Program Case Price Adjustment			(2.199566)			
7(B)(2) Case Pricing - 2009$$			55.36			

Historical Generation / Purchases from Wauna Project:

W/P Reference		Average Hourly Energy - MWh	Loads & Resources Study[2] Firm Energy - (aMW)
4	FY 1999	25.82575	
4	FY 2000	22.81016	
4	FY 2001	22.29335	23
3	FY 2002	23.90805	
3	FY 2003	22.26203	
3	FY 2004	23.33532	
2	FY 2005	21.58635	
	Average	23.14585857	

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APPENDIX D

BPA Programmatic Conservation Resources

Documentation of the Annual Amounts of Conservation Resources Available

AND

Documentation of Acquisition Cost
Annual Amounts Expensed and Amounts Capitalized and Financed

Used in Revising FY 2009 Rates

BPA's Wholesale Power 2007 Supplemental Rate Case

BPA Programatic Conservation - Historical Savings and Expenditures - Total Gross Amounts
ConMod, C&RD, and Market Transformation aMW Savings and Expenditures Before Adjustments

$ Millions of Dollars[1]

		(D) - (C)	From (C)	(D)		(A)			(B)	(C) (A) + (B)
				Annual			BPA Bonds Issued			Total
	Conser. Savings aMW[2,]	Amount Revenue Expensed[3,4]	Amount Debt Financed[7]	Expenditures[3] Per "Red Book"	Amort. Period Years	BPA Annual Conservation Capitalized[4]	Bond Principal Amount[5]	Bond Term[5]	Third-Party Financed Conser.[6]	Capitalized/ Debt Financed Conservation[7]
1982 Conser.	32.4	4.974	61.940	66.914	20	61.940			0.000	61.940
1983 Conser.	68.6	2.907	204.092	206.999	20	204.092	140.0	20	0.000	204.092
1984 Conser.	16.6	8.311	66.783	75.094	20	66.783	150.0	20	0.000	66.783
1985 Conser.	17.0	24.680	103.067	127.747	20	103.067	50.0	5	0.000	103.067
1986 Conser.	23.5	5.256	99.743	104.999	20	97.618	50.0	10	2.125	99.743
							50.0	5		0.000
1987 Conser.	19.7	3.928	71.631	75.559	20	67.381	75.0	20	4.250	71.631
							50.0	5		0.000
1988 Conser.	53.2	8.535	58.570	67.105	20	54.320	90.0	20	4.250	58.570
1989 Conser.	51.7	17.643	46.069	63.712	20	41.819	40.0	20	4.250	46.069
1990 Conser.	38.1	41.859	36.220	78.079	20	34.095			2.125	36.220
1991 Conser.	19.0	43.811	45.714	89.525	20	45.714			0.000	45.714
1992 Conser.	37.4	68.496	62.151	130.647	20	62.151	100.0	15	0.000	62.151
							50.0	20		0.000
1993 Conser.	59.6	59.432	96.717	156.149	20	96.717	90.0	20	0.000	96.717
1994 Conser.	51.3	58.812	121.242	180.054	20	115.030	50.0	20	6.212	121.242
							50.0	4		0.000
1995 Conser.	65.9	50.702	85.252	135.954	20	72.428	85.0	20	12.824	85.252
1996 Conser.	56.3	53.532	52.274	105.806	20	39.450	30.0	15	12.824	52.274
1997 Conser.	54.7	28.023	32.953	60.976	20	20.329	40.0	20	12.624	32.953
1998 Conser.	33.4	32.546	26.331	58.877	20	14.308			12.023	26.331
1999 Conser.	33.1	20.937	19.728	40.665	20	13.716			6.012	19.728
2000 Conser.	18.2	15.377	0.347	15.724	20	0.347	32.0	3	0.000	0.347
2001 Conser.	30.9	29.148	0.057	29.205	20	0.057			0.000	0.057
2002 Conser.	61.0	57.053	28.227	85.280	10	28.227	40.0	3	0.000	28.227
2003 Conser.	53.8	58.725	22.900	81.625	9	22.900			0.000	22.900
2004 Conser.	51.7	48.573	19.431	68.004	8	19.431	30.0	4	0.000	19.431
Adjustments	-1.9									
TOTALS 1982-2004	945.2	743.260	1,361.439	2,104.699		1,281.920	1,292.0		79.5	1,361.439
2005 Conser.	38.0	47.054	14.750	61.804	7	14.750			0.000	14.750
2006 Conser.	48.5	47.750	14.970	62.720	6	14.970	20.0	3	0.000	14.970
2007 Conser.	58.1	38.860	10.725	49.585	5	10.725	20.0	3	0.000	10.725
TOTALS 2005-2007	144.6	133.664	40.445	174.109		40.445	40.000		0.000	40.445
TOTALS 1982-2007	1,089.8	876.924	1,401.884	2,278.808		1,322.365	1,332.000		79.500	1,401.884

<u>Notes to Worksheet</u>:

1. Dollar costs are in nominal dollars associated with the year of expenditure.

2. The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts for the years 1982-2004 were obtained from the 2004 Conservation Resource Energy Data, "The Red Book". The annual savings totals for years 1982-2004 were based on Tables A and B using the sub-sector line amounts. The 2004 savings amounts attributable to building codes, market transformation efforts, ConMod, and C&RD are included in the savings totals. See the spread sheet titled "Total BPA Historical Programatic Conservation - Gross Amounts." The information in the 2004 Red Book provided greater detail than the 2005 edition for the years 1982-1999. The amounts in the table were updated and reconciled to the February 2005 Red Book addition. The annual savings and expenditure amounts for the years 2005-2007 were obtained from the 2008 Red Book.

3. Total Annual Expenditures for the years 1982-2004 are based on the "Total Cumulative Cost" column, Table D of the 2005 version of the "Red Book." The total expenditures include overhead loadings and indirect costs. Expenditures for building codes, market transformation, ConMod, and C&RD are included in the totals. In addition the amount of conservation investments funded with third-party debt are included in the totals. Annual expenditures for the years 2005-2007 are based on the "Total Incremental Cost" row, Table D of the 2008 version of the "Red Book." The total expenditures include overhead loadings and indirect costs. Expenditures for market transformation, C&RD, CRC, Energy Web Costs, and Conservation Support Costs are separately identified.

4. The annual amount capitalized is based on the additions to Annual Plant in Service based on the 2007 Supplemental Revenue Requirement Study Documentation WP-07 46A, Volume 1, Chapter 4 Tables 40 and 4P. This number is consistent with the information in BPA's annual reports after subtracting amortization of prior year investments.

5. The amount of conservation bonds issued and the term of the bonds is based on the 2007 Supplemental Revenue Requirement Study Documentation WP-07 46A, Volume 2, Chapter 5, Table 5A.

6. BPA has agreed to pay the debt service for Conservation and Renewable Energy System (CARES) a joint operating agency (JOA) of the State of Washington, Emerald Public Utility District, City of Tacoma (Tacoma Power), and Eugene Water and Electric Board. The amounts in the column Third-Party Financed Conservation represent the original issue amount (principle) of bonds to finance conservation projects.

7. Total Capitalized/Debt Financed Conservation is comprised of BPA capitalized expenditures that were financed with U.S. Treasury Bonds and the conservation that is capitalized under Nonfederal Projects in BPA's financial statements which consists of third-party funded conservation as outlined in note 6 above.

BPA's Wholesale Power 2007 Supplemental Rate Case
Total BPA Historical Programatic Conservation - Gross Amounts[1]

	1982	1983	1984	1985	1986	1987	1988
Residential - C&RD	30.0	49.5	10.6	9.0	9.3	5.0	5.0
Adj.	0.0	(0.6)	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	30.0	48.9	10.6	9.0	9.3	5.0	5.0
Commercial - C&RD	2.5	20.8	6.4	8.0	12.4	8.0	1.0
Adj.	(0.1)	(1.1)	(0.4)	(0.4)	(0.7)	(0.4)	(0.1)
Sub TOTAL	2.4	19.7	6.0	7.6	11.7	7.6	0.9
Industrial - C&RD	0.0	0.0	0.0	0.0	0.4	0.9	4.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)
Sub TOTAL	0.0	0.0	0.0	0.0	0.4	0.9	4.1
Agriculture - C&RD	0.0	0.5	0.5	0.9	0.9	1.3	1.4
Adj.	0.0	(0.5)	(0.5)	(0.9)	(0.9)	(1.3)	(1.4)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Multi-Sector - C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Building Codes	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Con/Mod	0.0	0.0	0.0	0.0	0.0	2.5	37.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	2.5	37.6
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	32.5	70.8	17.5	18.3	25.1	21.4	54.9
Adjustments	(0.1)	(2.2)	(0.9)	(1.3)	(1.6)	(1.7)	(1.7)
Net Annual Amt.	32.4	68.6	16.6	17.0	23.5	19.7	53.2

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the June 2005 Conservation Resource Energy Data, "The Red Book".

BPA's Wholesale Power 2007 Supplemental Rate Case

Total BPA Historical Programatic Conservation - Gross Amounts[1]

	1989	1990	1991	1992	1993	1994	Subtotal 1982-1994
Residential - C&RD	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.6)
Sub TOTAL	4.0	3.7	4.7	14.4	18.4	9.0	172.0
Commercial - C&RD	0.9	1.0	1.0	5.0	11.4	14.1	92.5
Adj.	0.0	(0.1)	(0.1)	(0.3)	(0.6)	(0.9)	(5.2)
Sub TOTAL	0.9	0.9	0.9	4.7	10.8	13.2	87.3
Industrial - C&RD	6.7	2.2	6.3	6.1	15.2	11.3	53.4
Adj.	(0.4)	(0.1)	(0.3)	(0.3)	(0.9)	(0.6)	(2.8)
Sub TOTAL	6.3	2.1	6.0	5.8	14.3	10.7	50.6
Agriculture - C&RD	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Adj.	(0.1)	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(6.2)
Sub TOTAL	1.3	0.1	1.1	0.8	1.5	1.4	6.2
Multi-Sector - C&RD	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Building Codes	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Con/Mod	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	52.2	38.3	19.5	38.1	61.3	53.0	502.9
Adjustments	(0.5)	(0.2)	(0.5)	(0.7)	(1.7)	(1.7)	(14.8)
Net Annual Amt.	51.7	38.1	19.0	37.4	59.6	51.3	488.1

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the June 2005 Conservation Resource Energy Data, "The Red Book".

BPA's Wholesale Power 2007 Supplemental Rate Case
Total BPA Historical Programatic Conservation - Gross Amounts[1]

	1995	1996	1997	1998	1999	2000
Residential - C&RD	3.4	1.4	0.6	0.7	0.6	0.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	3.4	1.4	0.6	0.7	0.6	0.3
Commercial - C&RD	9.3	5.3	4.8	6.8	0.5	0.0
Adj.	(0.5)	(0.2)	(0.2)	(0.3)	0.0	0.0
Sub TOTAL	8.8	5.1	4.6	6.5	0.5	0.0
Industrial - C&RD	18.2	11.8	6.7	0.2	0.2	0.0
Adj.	(1.1)	(0.6)	(0.4)	0.0	0.0	0.0
Sub TOTAL	17.1	11.2	6.3	0.2	0.2	0.0
Agriculture - C&RD	1.8	0.6	0.0	0.0	0.0	0.0
Adj.	(0.2)	(0.2)	0.0	0.0	0.0	0.0
Sub TOTAL	1.6	0.4	0.0	0.0	0.0	0.0
Multi-Sector - C&RD	20.1	23.6	27.9	12.9	13.4	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	20.1	23.6	27.9	12.9	13.4	0.0
Building Codes	14.9	14.6	15.3	13.1	14.4	12.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	14.9	14.6	15.3	13.1	14.4	12.9
Con/Mod	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Market Trans.	0.0	0.0	0.0	0.0	4.0	5.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	4.0	5.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	67.7	57.3	55.3	33.7	33.1	18.2
Adjustments	(1.8)	(1.0)	(0.6)	(0.3)	0.0	0.0
Net Annual Amt.	65.9	56.3	54.7	33.4	33.1	18.2

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the June 2005 Conservation Resource Energy Data, "The Red Book".

BPA's Wholesale Power 2007 Supplemental Rate Case

Total BPA Historical Programatic Conservation - Gross Amounts[1]

	2001	2002	2003	2004	Other Adjust's	FY 1982- FY 2004
Residential - C&RD	2.8	7.3	1.2	9.6		200.5
Adj.	(0.5)	(1.3)	(0.2)	0.0	0.2	(2.4)
Sub TOTAL	2.3	6.0	1.0	9.6	0.2	198.1
Commercial - C&RD	1.7	12.6	13.6	10.4		157.5
Adj.	0.0	0.2	0.2	0.0	(1.6)	(7.6)
Sub TOTAL	1.7	12.8	13.8	10.4	(1.6)	149.9
Industrial - C&RD	0.0	3.5	5.1	3.5		102.6
Adj.	0.0	(0.2)	0.0	0.0	(0.5)	(5.6)
Sub TOTAL	0.0	3.3	5.1	3.5	(0.5)	97.0
Agriculture - C&RD	0.0	0.0	0.0	0.0		14.8
Adj.	0.0	0.0	0.0	0.0		(6.6)
Sub TOTAL	0.0	0.0	0.0	0.0		8.2
Multi-Sector - C&RD	0.0	0.0	0.0	0.0		104.2
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0		104.2
Building Codes	12.4	13.0	4.2	3.9		188.5
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	12.4	13.0	4.2	3.9		188.5
Con/Mod	0.0	0.0	0.0	0.0		95.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0		95.9
Market Trans.	7.0	12.0	16.0	14.0		58.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	7.0	12.0	16.0	14.0		58.0
C&RD	9.6	17.7	17.5	13.1		57.9
Adj.	(2.1)	(3.8)	(3.8)	(2.8)	(5.2)	(17.7)
Sub TOTAL	7.5	13.9	13.7	10.3	(5.2)	40.2
Totals before Adj.	33.5	66.1	57.6	54.5		979.9
Adjustments	(2.6)	(5.1)	(3.8)	(2.8)	(1.9)	(34.7)
Net Annual Amt.	30.9	61.0	53.8	51.7	(1.9)	945.2

Total Above	945.2
Less ConMod	(95.9)
June 2005 Red Book Table A page 5	849.3

BPA's Wholesale Power 2007 Supplemental Rate Case
Total BPA Historical Programatic Conservation - Gross Amounts[1]

	2005	2006	2007	Other Adjust's	FY 2005-FY 2007
Residential	10.5	10.7	13.4		34.6
C&RD/CRC Adj.	(8.5)	(5.0)	(6.9)		(20.4)
Sub TOTAL	2.0	5.7	6.5		14.2
Commercial	9.5	14.6	9.4		33.5
C&RD/CRC Adj.	(0.4)	(0.8)	(3.2)		(4.4)
Sub TOTAL	9.1	13.8	6.2		29.1
Industrial	3.4	8.2	6.2		17.8
C&RD/CRC Adj.	(0.6)	(2.6)	(5.3)		(8.5)
Sub TOTAL	2.8	5.6	0.9		9.3
Agriculture	0.1	0.5	4.2		4.8
C&RD/CRC Adj.	(0.1)	(0.1)	(2.9)		(3.1)
Sub TOTAL	0.0	0.4	1.3		1.7
Multi-Sector	1.9	0.2	0.1		2.2
C&RD/CRC Adj.	0.0	0.0	0.0		0.0
Sub TOTAL	1.9	0.2	0.1		2.2
Market Trans.	12.7	14.2	24.9		51.8
Adj.	0.0	(0.6)	(3.6)		(4.2)
Sub TOTAL	12.7	13.6	21.3		47.6
C&RD and CRC	9.6	9.1	21.9		40.6
Adj.	(0.1)	0.1	0.0		0.0
Sub TOTAL	9.5	9.2	21.9		40.6
Totals before Adj.	38.1	48.4	58.2		144.7
Adjustments	(0.1)	0.1	(5.6)		(5.6)
Net Annual Amt.	38.0	48.5	52.6		139.1

Adjustment Detail:			
Utility Self Funded HWM:			
Residentail			(1.37)
Commercial			(0.96)
Industrial			(0.63)
Market Trans.			(2.54)
Rounding	(0.10)	0.10	(0.10)
Totals	(0.10)	0.10	(5.60)

BPA's Wholesale Power 2007 Supplemental Rate Case

BPA 1982-2004 Historical Programatic Conservation - After Adjustments [1]

	1982	1983	1984	1985	1986	1987	1988
Residential - C&RD	30.0	49.5	10.6	9.0	9.3	5.0	5.0
Adj.	0.0	(0.6)	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	30.0	48.9	10.6	9.0	9.3	5.0	5.0
Commercial - C&RD	2.5	20.8	6.4	8.0	12.4	8.0	1.0
Adj.	(0.1)	(1.1)	(0.4)	(0.4)	(0.7)	(0.4)	(0.1)
Sub TOTAL	2.4	19.7	6.0	7.6	11.7	7.6	0.9
Industrial - C&RD	0.0	0.0	0.0	0.0	0.4	0.9	4.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)
Sub TOTAL	0.0	0.0	0.0	0.0	0.4	0.9	4.1
Agriculture - C&RD	0.0	0.5	0.5	0.9	0.9	1.3	1.4
Adj.	0.0	(0.5)	(0.5)	(0.9)	(0.9)	(1.3)	(1.4)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Multi-Sector - C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Building Codes	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Con/Mod	0.0	0.0	0.0	0.0	0.0	2.5	37.6
Adj.	0.0	0.0	0.0	0.0	0.0	(2.5)	(37.6)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	32.5	70.8	17.5	18.3	25.1	21.4	54.9
Adjustments	(0.1)	(2.2)	(0.9)	(1.3)	(1.6)	(4.2)	(39.3)
Net Annual Amt.	32.4	68.6	16.6	17.0	23.5	17.2	15.6

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book."

BPA's Wholesale Power 2007 Supplemental Rate Case

BPA 1982-2004 Historical Programatic Conservation - After Adjustments [1]

	1989	1990	1991	1992	1993	1994	1982-1994 Totals
Residential - C&RD	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.6)
Sub TOTAL	4.0	3.7	4.7	14.4	18.4	9.0	172.0
Commercial - C&RD	0.9	1.0	1.0	5.0	11.4	14.1	92.5
Adj.	0.0	(0.1)	(0.1)	(0.3)	(0.6)	(0.9)	(5.2)
Sub TOTAL	0.9	0.9	0.9	4.7	10.8	13.2	87.3
Industrial - C&RD	6.7	2.2	6.3	6.1	15.2	11.3	53.4
Adj.	(0.4)	(0.1)	(0.3)	(0.3)	(0.9)	(0.6)	(2.8)
Sub TOTAL	6.3	2.1	6.0	5.8	14.3	10.7	50.6
Agriculture - C&RD	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Adj.	(0.1)	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(6.2)
Sub TOTAL	1.3	0.1	1.1	0.8	1.5	1.4	6.2
Multi-Sector - C&RD	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Building Codes	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Con/Mod	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Adj.	(30.9)	(24.9)	0.0	0.0	0.0	0.0	(95.9)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	52.2	38.3	19.5	38.1	61.3	53.0	502.9
Adjustments	(31.4)	(25.1)	(0.5)	(0.7)	(1.7)	(1.7)	(110.7)
Net Annual Amt.	20.8	13.2	19.0	37.4	59.6	51.3	392.2

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book."

BPA's Wholesale Power 2007 Supplemental Rate Case
BPA 1982-2004 Historical Programatic Conservation - After Adjustments[1]

	1995	1996	1997	1998	1999	2000
Residential less C&RD	3.4	1.4	0.6	0.7	0.6	0.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	3.4	1.4	0.6	0.7	0.6	0.3
Commercial less C&RD	9.3	5.3	4.8	6.8	0.5	0.0
Adj.	(0.5)	(0.2)	(0.2)	(0.3)	0.0	0.0
Sub TOTAL	8.8	5.1	4.6	6.5	0.5	0.0
Industrial less C&RD	18.2	11.8	6.7	0.2	0.2	0.0
Adj.	(1.1)	(0.6)	(0.4)	0.0	0.0	0.0
Sub TOTAL	17.1	11.2	6.3	0.2	0.2	0.0
Agriculture less C&RD	1.8	0.6	0.0	0.0	0.0	0.0
Adj.	(0.2)	(0.2)	0.0	0.0	0.0	0.0
Sub TOTAL	1.6	0.4	0.0	0.0	0.0	0.0
Multi-Sector less C&RD	20.1	23.6	27.9	12.9	13.4	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	20.1	23.6	27.9	12.9	13.4	0.0
Building Codes[4]	14.9	14.6	15.3	13.1	14.4	12.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	14.9	14.6	15.3	13.1	14.4	12.9
Con/Mod	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Market Transformation[3]	0.0				4.0	5.0
Adj.	0.0	0.0	0.0	0.0	(2.8)	(3.5)
Sub TOTAL	0.0	0.0	0.0	0.0	1.2	1.5
C&RD[2]	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	67.7	57.3	55.3	33.7	33.1	18.2
Adjustments	(1.8)	(1.0)	(0.6)	(0.3)	(2.8)	(3.5)
Net Annual Amt.	65.9	56.3	54.7	33.4	30.3	14.7

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book."

BPA's Wholesale Power 2007 Supplemental Rate Case

BPA 1982-2004 Historical Programatic Conservation - After Adjustments[1]

	2001	2002	2003	2004	Other Adjust's	TOTALS FY 1982-FY 2004
Residential less C&RD	2.8	7.3	1.2	9.6		200.5
Adj.	(0.5)	(1.3)	(0.2)	0.0	0.2	(2.4)
Sub TOTAL	2.3	6.0	1.0	9.6		198.1
Commercial less C&RD	1.7	12.6	13.6	10.4		157.5
Adj.	0.0	0.2	0.2	0.0	(1.6)	(7.6)
Sub TOTAL	1.7	12.8	13.8	10.4		149.9
Industrial less C&RD	0.0	3.5	5.1	3.5		102.6
Adj.	0.0	(0.2)	0.0	0.0	(0.5)	(5.6)
Sub TOTAL	0.0	3.3	5.1	3.5		97.0
Agriculture less C&RD	0.0	0.0	0.0	0.0		14.8
Adj.	0.0	0.0	0.0	0.0	0.0	(6.6)
Sub TOTAL	0.0	0.0	0.0	0.0		8.2
Multi-Sector less C&RD	0.0	0.0	0.0	0.0		104.2
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0		104.2
Building Codes[4]	12.4	13.0	4.2	3.9		188.5
Adj.	0.0	(13.0)	(4.2)	(3.9)	0.0	(21.1)
Sub TOTAL	12.4	0.0	0.0	0.0		167.4
Con/Mod	0.0	0.0	0.0	0.0		95.9
Adj.	0.0	0.0	0.0	0.0	0.0	(95.9)
Sub TOTAL	0.0	0.0	0.0	0.0		0.0
Market Transformation[3]	7.0	12.0	16.0	14.0		58.0
Adj.	(4.9)	(8.4)	(11.2)	(9.8)	0.0	(40.6)
Sub TOTAL	2.1	3.6	4.8	4.2		17.4
C&RD[2]	7.5	13.9	13.7	10.3		45.4
Adj.	(7.5)	(13.9)	(13.7)	(10.3)	0.0	(45.4)
Sub TOTAL	0.0	0.0	0.0	0.0		0.0
Totals before Adj.	31.4	62.3	53.8	51.7		967.4
Adjustments[6]	(12.9)	(36.6)	(29.1)	(24.0)	3.3	(220.0)
Net Annual Amt.	18.5	25.7	24.7	27.7	3.3	747.4

Total Above	747.4
Plus C&RD Reductions	45.4
Plus Bldg. Code Reductions	21.1
Difference in C&RD	(5.2)
Plus Market Transformation Reductions	40.6
2004 Red Book Table A page 5	849.3

BPA's Wholesale Power 2007 Supplemental Rate Case

BPA 2005-2007 Historical Programatic Conservation - After Adjustments [1]

	2005	2006	2007	Other Adjust's	FY 2005-FY 2007
Residential less C&RD	2.0	5.7	5.1		12.8
Adj.					
Sub TOTAL	2.0	5.7	5.1		12.8
Commercial less C&RD	9.1	13.8	5.2		28.1
Adj.					
Sub TOTAL	9.1	13.8	5.2		28.1
Industrial less C&RD	2.8	5.6	0.3		8.7
Adj.					
Sub TOTAL	2.8	5.6	0.3		8.7
Agriculture less C&RD	0.0	0.4	1.3		1.7
Adj.					
Sub TOTAL	0.0	0.4	1.3		1.7
Multi-Sector less C&RD	1.9	0.2	0.1		2.2
Adj.					
Sub TOTAL	1.9	0.2	0.1		2.2
Building Codes[4]	0.0	0.0	0.0		0.0
Adj.	0.0	0.0	0.0		0.0
Sub TOTAL	0.0	0.0	0.0		0.0
Con/Mod	0.0	0.0	0.0		0.0
Adj.	0.0	0.0	0.0		0.0
Sub TOTAL	0.0	0.0	0.0		0.0
Market Transformation[3]	12.7	13.6	18.8		45.1
Adj.	(8.5)	(9.1)	(12.6)		(30.2)
Sub TOTAL	4.2	4.5	6.2		14.9
C&RD and CRC[2]	9.5	9.2	21.9		40.6
Adj.	(9.5)	(9.2)	(11.6)		(30.3)
Sub TOTAL	0.0	0.0	10.3		10.3
Totals before Adj.	38.0	48.5	52.7		139.2
Adjustments[7]	(18.0)	(18.3)	(24.2)	0.0	(60.5)
Net Annual Amount 7(b)(2)	20.0	30.2	28.5		78.7
Adjustment Detail:					
C&RD / CRC Reductions	9.5	9.2	11.6		30.3
Market Trans. Reductions	8.5	9.1	12.6		30.2
Utility Self Funded HWM			5.5		5.5
Rounding			(0.1)		(0.1)
2007 Red Book Table A page 8	38.0	48.5	58.1		144.6

Notes Concerning Conservation Savings Adjustments:

1. The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts for 1982-2003 were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book." The annual saving totals for years 1982-1999 were based on Table B2 , pages 7-8, using the sub-sector line amounts. The annual savings for the years 2000-2003 are based on Table B1, page 6 of The 2004 Red Book, using the amounts for ConAug by sector plus the low income residential weatherization amounts. The information in the 2004 Red Book provided greater detail than the 2005 edition of the Red Book concerning the amount of conservation savings for the years 1982-1999. The final results in the tables were updated and reconciled to the February 2005 Red Book. Saving amounts attributable to ConMod, and C&RD have been totally removed from the cumulative totals for FY's 1982-2006. See the additional notes below on adjustments made to the Red Book's gross amounts. The annual savings amounts for 2005-2007 were obtained from the 2008 Conservation Resource Energy Data, "The Red Book." The annual saving totals for years 2005-2007 were based on Table B , pages 6-7, using the sub-sector line amounts.

2. Savings and expenditures attributable to C&RD were removed in total for the years prior to 2007 because there was not adequate compliance efforts in place during those years to have sufficient certainty that the savings were achieved. BPA's post -2006 Conservation Program has provided additional compliance requirements surrounding the CRC program to help ensure the achievement of conservation savings associated with the granting of CRC credits. The majority of CRC expenditures are received by non-load following utilities that purchase the Slice and Flat-Block power products. The Administrator's load obligations to these utilities has not been reduced, (contract power amounts have not been decremented for the conservation savings) thus BPA will not receive a direct benefit from CRC expenditures associated with non-load following customers during the Section 7(b)(2) rate test period. BPA does receive a direct benefit from load following customers associated with the conservation that occurs in those utility's service territories. Because of the additional controls surrounding the achievement of conservation savings during the post 2006 time period, and because BPA does receive a direct benefit from expenditures that occur in load following utility service territories, the portion of the CRC savings attributable to load following utilities has been included in the Section 7(b)(2) resource stack.

The reduction in conservation savings attributable to the CRC program available to the Section 7(b)(2) resource stack is outlined as follows:

a) Load following BPA customer loads are forecasted at 4,292 aMW for FY 2009, non-load following load is forecasted at 4,821, for a total of 9,113aMW (Total Retail Loads). Non-load following loads represent 53% of total forecasted BPA loads and load following loads represent 47% of BPA's total loads. Thus 53% of the saving attributable to FY 2007 CRC efforts will be removed from the 7(b)(2) resource stack.

Notes Concerning Conservation Savings Adjustments Continued:

3. BPA's market transformation efforts have been achieved through the Northwest Energy Efficiency Alliance (NEEA) for the most part during this period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA paid for approximately one-half of NEEA's operating budgets during the 1999-2008 time frame. BPA plans to continue funding NEEA's efforts through the 2013 time period at the same level of support. BPA's "Red Book" claims one half of the regional savings attributable to NEEA's efforts commensurate with it's level of funding. The expenditures that BPA pays NEEA however, has only a partial impact on reducing the Administrator's load obligations. The calculation of the amount of benefit that BPA receives is calculated as follows:

Forecasted FY 2009 Regional Loads (No DSI's)	21,205.0	aMW	100%
BPA's Forecasted FY 2007 Loads (No DSI's)	7,406.0	aMW	35%

DSI loads were excluded from both amounts because market transformation efforts do not impact DSI loads. Of the total BPA forecasted loads of 7,406aMW (35%), there is no reduction in contracted power purchases for BPA's non-load following customers. No reduction of purchased power amounts in slice and block power purchase contracts due to NEEA savings were made during this period of time, and no decrements are forecasted for the 2006-2011 time period. The amount of power that BPA provides to load following and non-load following customers is as follows:

Forecasted FY 2007 Total Retail Load:			
Load Following Customers	4,292.0	aMW	47%
Non-Load Following Customers	4,821.0	aMW	53%
	9,113.0	aMW	100%

For every megawatt of conservation savings that is achieved by NEEA's market transformation efforts, BPA's load obligations are reduced by approximately 16.45 percent (35% x 47%). Because the Red Book only claims half of the NEEA savings it is necessary to adjust the calculation below that is based on total regional loads by doubling the final savings amount. The adjustment necessary to reflect just the direct benefit of savings to BPA loads is to reduce the savings in the table by sixty-seven percent (67%). This percentage is derived by doubling the 16.45% above and subtracting this total from 100% of the gross savings contained in the Red Book (100% -(2 x 16.45%)) = 67%.

4. Adjustment were made to remove savings attributable to building codes for the years after 2001. BPA's Conservation Program staff are of the opinion that the benefits from earlier BPA expenditures to achieve Model Energy Code standards had largely been achieved by this time. The savings for the 7(b)(2) resource stack should have a high degree of assurance that the conservation savings would be able to reduce 7(b)(2) Case loads.

5. As previously noted in the table of Gross Conservation Savings, The 2005 Red Book totals have excluded the savings form ConMod Conservation investments that were placed primarily with the aluminum reduction industry. Since most of these plants are no longer operating, and since BPA is not planning to meet future power loads from this industry, the conservation savings from these past investments is not available to reduce loads in the 2007-2013 time period of the 7(b)(2) rate test. The expenditures for ConMod investments were left in the 2005 Red Book to meet the Red Book's objective of accounting for all conservation expenditures. The expenditures for past ConMod investments were removed from the expenditure totals that were included in the 7(b)(2) resource stack.

Notes Concerning Conservation Savings Adjustments Continued:

6. Starting in FY 2007 the Red Book started reporting utility Self-Funded Conservation Savings in the conservation savings totals. These savings were undertaken by BPA's customers without BPA funding. No expenditures for these savings were reported in the Red Book. These savings for FY 2007 totaling 5.5 aMW were removed from the totals to arrive at BPA's conservation efforts that should be included in the 7(b)(2) resource stack.

7. The following adjustments were made to the 2005 Red Book's conservation savings for the years 1982-2004:

Building Code Savings	21.1	aMW
Market Transformation Saving	40.6	aMW
C&RD Savings	40.2	aMW
	101.9	aMW

The total conservation savings per the Red Book for FY1982-2004 was 849.3 aMW, the total savings included in the 7(b)(2) resource stack for those years was 747.4aMW.

8. The following adjustments were made to the 2008 Red Book's conservation savings for the years 2005-2007:

Utility Self Funded HWM	5.4	aMW
Market Transformation Savings	30.2	aMW
C&RD and CRC Savings	30.3	aMW
	65.9	aMW

The total conservation savings per the Red Book for FY2005-2007 was 144.6 aMW, the total savings included in the 7(b)(2) resource stack for those years was 78.7 aMW.

BPA's Wholesale Power 2007 Supplemental Rate Case

Total Historical Conservation Expenditures -1982-2007, Per Red Book, Adjusted for Plant Accounting Capitalized Conservation Expenditures

($000) [1]

Year	Total Incremental Yearly Costs Table D Red Book	CAPITALIZED COSTS: Total Capitalized Costs	Third Party Financing Costs/ Original Issue Amount	BPA CAPITALIZED COSTS: Capitalized Conser. Costs	ConAcq Costs	ConAug Costs	Legacy Conser. Costs	EXPENSED CONSERVATION COSTS: Total Expense Costs	Support Costs[2]	Market Transform. Costs[5]	Con/Mod Costs[3]	C&RD CRC Total Costs[4]	Energy WEB & New Initiatives	Other Conser. Expense Costs	TOTAL CONSER. COSTS	Gross Conser. Savings per Red Book
1982	66,914	61,940	0	61,940		0	61,940	4,974	4,974	0	0	0	0	0	66,914	32.4
1983	206,999	204,092	0	204,092		0	204,092	2,907	2,907	0	0	0	0	0	206,999	68.6
1984	75,094	66,783	0	66,783		0	66,783	8,311	7,589	0	0	0	0	722	75,094	16.6
1985	127,747	103,067	0	103,067		0	103,067	24,680	20,232	0	0	0	0	4,448	127,747	17.0
1986	104,999	99,743	2,125	97,618		0	97,618	5,256	5,256	0	0	0	0	0	104,999	23.5
1987	75,559	71,631	4,250	67,381		0	67,381	3,928	3,928	0	0	0	0	0	75,559	19.7
1988	67,105	58,570	4,250	54,320		0	54,320	8,535	6,654	0	1,881	0	0	0	67,105	53.2
1989	63,712	46,069	4,250	41,819		0	41,819	17,643	12,917	0	4,726	0	0	0	63,712	51.7
1990	78,079	36,220	2,125	34,095		0	34,095	41,859	5,359	0	6,063	0	0	30,437	78,079	38.1
1991	89,525	45,714	0	45,714		0	45,714	43,811	5,106	0	6,254	0	0	32,451	89,525	19.0
1992	130,647	62,151	0	62,151		0	62,151	68,496	4,134	0	4,553	0	0	59,809	130,647	37.4
1993	156,149	96,717	0	96,717		0	96,717	59,432	8,119	0	4,179	0	0	47,134	156,149	59.6
1994	180,054	121,242	6,212	115,030		0	115,030	58,812	8,210	0	6,462	0	0	44,140	180,054	51.3
1995	135,954	85,252	12,824	72,428		0	72,428	50,702	7,915	0	4,045	0	0	38,742	135,954	65.9
1996	105,806	52,274	12,824	39,450		0	39,450	53,532	7,863	0	4,595	0	0	41,074	105,806	56.3
1997	60,976	32,953	12,624	20,329		0	20,329	28,023	14,800	3,900	2,744	0	0	6,579	60,976	54.7
1998	58,877	26,331	12,023	14,308		0	14,308	32,546	12,200	12,000	2,358	0	0	5,988	58,877	33.4
1999	40,665	19,728	6,012	13,716		0	13,716	20,937	10,571	5,600	280	0	1,400	3,086	40,665	33.1
2000	15,724	347	0	347		0	347	15,377	3,077	12,000	0	0	300	0	15,724	18.2
2001	29,205	57	0	57		3,688	(3,631)	29,148	6,200	9,600	0	9,243	1,450	2,655	29,205	30.9
2002	85,280	28,227	0	28,227		28,201	26	57,053	6,193	7,750	0	39,910	3,200	0	85,280	61.0
2003	81,625	22,900	0	22,900		23,793	(893)	58,725	3,594	9,300	0	41,439	4,392	0	81,625	53.8
2004	68,004	19,431	0	19,431		19,117	314	48,573	5,315	9,700	0	32,752	806	0	68,004	51.7
																(1.9)
TOTALS 1982-2004	2,104,699	1,361,439	79,519	1,281,920		74,799	1,207,121	743,260	173,113	69,850	48,140	123,344	11,548	317,265	2,104,699	945.2
2005	61,804	14,750	0	14,750		14,750	0	47,054	8,189	7,956	0	24,608	602	5,699	61,804	38.0
2006	62,720	14,970	0	14,970		14,970	0	47,750	7,577	10,140	0	19,736	969	9,328	62,720	48.5
2007	49,585	10,725	0	10,725	6,139	4,586	0	38,860	7,020	9,925	0	20,886	1,817	(788)	49,585	58.1
TOTALS 2005-2007	174,109	40,445	0	40,445	6,139	34,306	0	133,664	22,786	28,021	0	65,230	3,388	14,239	174,109	144.6
TOTALS 1982-2007	2,278,808	1,401,884	79,519	1,322,365	6,139	109,105	1,207,121	876,924	195,899	97,871	48,140	188,574	14,936	331,504	2,278,808	1,089.8

BPA's Wholesale Power 2007 Supplemental Rate Case
NET Historical Conservation Savings and Expenditures 1982-2007
With Expenditure Adjustments for ConMod and C&RD
Savings Adjustments for C&RD, CRC, Market Transformation, and Building Codes
($000) [1]

Year	Total Incremental Costs / Subtotal Cost Allocations	(-) C&RD[4] Cost Adjustments	(-) ConMod[3] Cost Adjustments	(-) Market Trans.[5] Cost Adjustments	Adjusted Net Annual Costs	Total Expense Costs	Capitalized Conservation Costs	Net Conser. Savings as Adjusted
1982	66,914	0	0	0	66,914	4,974	61,940	32.4
1983	206,999	0	0	0	206,999	2,907	204,092	68.6
1984	75,094	0	0	0	75,094	8,311	66,783	16.6
1985	127,747	0	0	0	127,747	24,680	103,067	17.0
1986	104,999	0	0	0	104,999	5,256	99,743	23.5
1987	75,559	0	0	0	75,559	3,928	71,631	17.2
1988	67,105	0	(1,881)	0	65,224	6,654	58,570	15.6
1989	63,712	0	(4,726)	0	58,986	12,917	46,069	20.8
1990	78,079	0	(6,063)	0	72,016	35,796	36,220	13.2
1991	89,525	0	(6,254)	0	83,271	37,557	45,714	19.0
1992	130,647	0	(4,553)	0	126,094	63,943	62,151	37.4
1993	156,149	0	(4,179)	0	151,970	55,253	96,717	59.6
1994	180,054	0	(6,462)	0	173,592	52,350	121,242	51.3
1995	135,954	0	(4,045)	0	131,909	46,657	85,252	65.9
1996	105,806	0	(4,595)	0	101,211	48,937	52,274	56.3
1997	60,976	0	(2,744)	0	58,232	25,279	32,953	54.7
1998	58,877	0	(2,358)	0	56,519	30,188	26,331	33.4
1999	40,665	0	(280)	0	40,385	20,657	19,728	30.3
2000	15,724	0	0	0	15,724	15,377	347	14.7
2001	29,205	(9,243)	0	0	19,962	19,905	57	18.5
2002	85,280	(39,910)	0	0	45,370	17,143	28,227	25.7
2003	81,625	(41,439)	0	0	40,186	17,286	22,900	24.7
2004	68,004	(32,752)	0	0	35,252	15,821	19,431	31.0
	2,104,699	(123,344)	(48,140)	0	1,933,215	571,776	1,361,439	747.4
2005	61,804	(24,608)	0	0	37,196	22,446	14,750	20
2006	62,720	(19,736)	0	0	42,984	28,014	14,970	30.2
2007	49,585	0	0	0	49,585	38,860	10,725	28.5
	174,109	(44,344)	0	0	129,765	89,320	40,445	78.7
	2,278,808	(167,688)	(48,140)	0	2,062,980	661,096	1,401,884	826.1

BPA's Wholesale Power 2007 Supplemental Rate Case
NET Historical Conservation Savings and Expenditures 1982-2007
With Expenditure Adjustments for ConMod and C&RD
Savings Adjustments for C&RD, CRC, Market Transformation and Building Codes

<u>Notes Concerning Expenditure Adjustments</u>:

1. Dollar costs for FY1982-2007 are in nominal dollars associated with the year of expenditure. Costs for FY1982-2004 were obtained from Table D of the 2005 Conservation Resource Energy Data, "The Red Book." Costs for FY2005-2007 were obtained from Table D of the 2008 Red Book.

2. Support costs are non-sector specific and consist of resource planning costs through FY 1987, Research Development & Demonstration, prior year adjustments, education efforts, and environmental conservation costs.

3. As previously noted in the table of Gross Conservation Savings, The 2005 Red Book totals have excluded the savings form ConMod Conservation investments that were placed primarily with the aluminum reduction industry. Since most of these plants are no longer operating, and since BPA is not planning to meet future power loads from this industry, the conservation savings from these past investments is not available to reduce loads in the 2007-2013 time period of the 7(b)(2) rate test. The expenditures for ConMod investments were left in the Red Book to meet the Red Book's objective of accounting for all the costs of acquiring conservation expenditures. The expenditures for past ConMod investments has been removed from the expenditure totals that were included in the 7(b)(2) resource stack total.

4. The C&RD investments were costs that were not included in BPA's revenue requirement in determining "base" rate levels for years prior to 2007. They were added after the determination of base rates and were credited back to customers as credits on their power bills in return for agreeing to invest the money in conservation efforts or renewable resources. The controls surrounding the achievement of this conservation during the 2002-2006 time period was less than past practices making the savings from these expenditures less assured. The majority of the utilities participating in this program were not "load following" customers and the Administrator's load obligations to these customers was not reduced (no decrementing of contract obligations occurred). For these reasons the savings and expenditures associated with the C&RD program for 2002-2006 was "netted" out of those years conservation efforts.

No reduction in expenditures for the CRC program for FY 2007 were made. Unlike the FY2002-2006 time period when the C&RD costs were not included in the revenue requirement, the WP-07 revenue requirement included CRC costs. The rates charged all BPA customers included CRC costs. It would be inequitable and not feasible to conduct a CRC program where only load-following customers were eligible to participate. In order to achieve the conservation savings that occur in the service territories of full-requirements customers, BPA also needs to undertake the CRC program for BPA's other customers who pay for CRC costs. In order for BPA and it's customers to meet their portion of the NWPPC's regional targets, the total expenditures for CRC are required to be incurred. The controls surrounding documentation and verification of CRC savings were also improved compared to the controls and verification procedures that pertained to the C&RD program prior to FY 2007. As outlined in Note 3 to the "BPA 1982-2007 Historical Programmatic Conservation - After Adjustments" worksheet, fifty-three percent of the saving attributable to FY 2007 CRC efforts were attributable to non-load following loads that were not decremented for the savings achieved. These non-load following savings were removed from the 7(b)(2) resource stack for FY2007-2013.

<u>Notes Concerning Expenditure Adjustments</u>:

5. BPA's market transformation efforts have been achieved through the Northwest Energy Efficiency Alliance (NEEA) for the most part during this period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA paid for approximately one-half of NEEA's operating budgets during the 1997-2004 time frame. The expenditures that BPA pays NEEA has only a partial impact on reducing the Administrator's load obligation. The market transformation savings were reduced by seventy percent, see this calculation at Note 3 to the work sheet "BPA 1982-2007 Programmatic Conservation - After Adjustments." The amount of market transformation expenditures were not reduced. The reason for this is the fact that the amount that BPA paid NEEA was so material in amount, that it was critical in sustaining market transformation efforts in the region. In order to achieve the thirty-three percent of savings that were included in the savings total, BPA would have needed to fund the program at approximately the same level.

6. Adjustments were made to remove the savings attributable to building codes for the years after 2001. It was thought that the benefits from earlier BPA expenditures to achieve Model Energy Code standards had largely been achieved by this time. The savings for the 7(b)(2) resource stack should be conservatively stated with a high degree of assurance that the conservation savings would be able to reduce loads. No direct expenditures by BPA for building code efforts occurred during FY2002-2007, so no expenditure adjustments are necessary.

7. The historical expenditures reflected in the annual expenditure totals contained in the Red Book contain the direct costs along with indirect and overhead costs that were necessary to acquire the conservation savings reported for the year. The expenditure totals do not contain any costs associated with the financing of conservation efforts. The 2002 and 2007 rates analysis models (RAM) that were used to perform the Lookback analysis does finance that portion of a year's expenditures that were capitalized, using a 20-year period for investments made during 1982-2001 and 15-years for those investments incurred after 2001. The interest rates used are based on the Financing Study that was performed by BPA's financial advisor for the respective original rate case. For the WP-07 Supplemental rate proposal's revision of FY 2009 rates, all capitalized conservation investments are amortized and financed over a period of 15 years. The first-year expensed costs are treated as deferred charges under SFAS No. 71 and are amortized and financed over a one to fifteen-year period. The interest rates used to finance conservation resources were based on Public Financial Management's revised financing study.

Total BPA Conservation Program - Projected Expenditures
GROSS EXPENDITURES - 2008-2013
($1,000)[1]

	Energy Efficiency Staffing Costs1	Indirect & Overhead Costs	Corporate G&A Costs	Total Staffing, Indirect, & G&A Costs	Market Transformation Costs	Expense Agreements & Grants	CRC Costs	Infrastructure Support & Evaluation Costs	Acquisition Capital Costs	Total Direct Program Costs	Projected Period Costs Energy Efficiency		Capitalized/ Debt Financed	Expensed	Total Projected Conser. Savings aMW
2008	7,465	1,674	9,500	18,639	10,000	5,000	34,000	4,085	15,000	68,085	86,724	#	15,000	71,724	52.0
2009	7,140	2,595	9,385	19,120	10,000	5,812	32,000	7,000	32,000	86,812	105,932	#	32,000	73,932	52.0
2010	7,657	3,562	10,585	21,804	12,000	5,000	32,000	14,000	56,000	119,000	140,804	#	56,000	84,804	56.0
2011	7,927	3,788	10,789	22,504	12,000	5,000	32,000	14,000	56,000	119,000	141,504	#	56,000	85,504	56.0
2012	8,207	4,139	11,202	23,548	12,000	6,000	32,000	15,000	56,000	121,000	144,548	#	56,000	88,548	56.0
2013	8,491	4,220	11,581	24,292	12,000	6,000	32,000	15,000	56,000	121,000	145,292	#	56,000	89,292	56.0
Totals	46,887	19,978	63,042	129,907	68,000	32,812	194,000	69,085	271,000	634,897	764,804	#	271,000	493,804	328.0

Net BPA Conservation Program - Section 7 (b)(2) - Projected Expenditures
NET EXPENDITURES - 2008-2013
($1,000)

	Energy Efficiency Staffing Costs1	Indirect & Overhead Costs	Corporate G&A Costs	Total Staffing, Indirect, & G&A Costs	Market Transformation Costs	Expense Agreements & Grants	CRC Costs	Infrastructure Support & Evaluation Costs	Acquisition Capital Costs	Total Direct Program Costs	Projected Period Costs Energy Efficiency		Capitalized/ Debt Financed	Expensed	Total Projected Conser. Savings aMW
2008	7,465	1,674	9,500	18,639	10,000	5,000	34,000	4,085	15,000	68,085	86,724	#	15,000	71,724	34.7
2009	7,140	2,595	9,385	19,120	10,000	5,812	32,000	7,000	32,000	86,812	105,932	#	32,000	73,932	34.7
2010	7,657	3,562	10,585	21,804	12,000	5,000	32,000	14,000	56,000	119,000	140,804	#	56,000	84,804	39.5
2011	7,927	3,788	10,789	22,504	12,000	5,000	32,000	14,000	56,000	119,000	141,504	#	56,000	85,504	39.5
2012	8,207	4,139	11,202	23,548	12,000	6,000	32,000	15,000	56,000	121,000	144,548	#	56,000	88,548	39.5
2013	8,491	4,220	11,581	24,292	12,000	6,000	32,000	15,000	56,000	121,000	145,292	#	56,000	89,292	39.5
Totals	46,887	19,978	63,042	129,907	68,000	32,812	194,000	69,085	271,000	634,897	764,804	#	271,000	493,804	227.4

Difference in Conservation Expenditures and Savings Contained in Resource Stack **$0** 100.6

BPA's Wholesale Power 2007 Supplemental Rate Case
Projected Conservation GROSS and NET EXPENDITURES - 2008-2013
Net BPA Conservation Program - Section 7 (b)(2) Amounts

Notes - Adjustments Made to BPA's Conservation Program Expenditure Amounts to Arrive at Section 7 (b)(2) Amounts

1. Dollar costs are in the nominal dollars associated with the year of expenditure. The conservation expenditure projections for 2008-2013 come from BPA's program budgets for those years. The expenditure projections for the years 2009-2011 come from BPA's Conservation Program Proposals that were finalized in the Integrated Program Review process. The expenditure projections for 2012-2013 were based on the assumption that the conservation program design for 2009-2011 continued during these two years.

2. Third-party debt service costs are subtracted out of the 7(b)(2) Case amounts so that the expenditure totals reflect only the actual expenditures/costs for acquiring savings for that year. The costs in the resource stack are net of all financing costs. Annual debt service costs are included in the annual revenue requirements for each year by 2007RAM using the interest rate projections provided by BPA's Financial Advisor associated with the hypothetical Joint Operating Agency's funding of all resources in performing the Section 7(b)(2) rate test.

3. No reduction in expenditures for the CRC program were made. Unlike the FY2002-2006 time period when the C&RD cost were not included in the revenue requirement, the WP-07 revenue requirement includes CRC costs. The rates charged all BPA customers include CRC costs. It would be inequitable and not feasible to conduct a CRC program where only load-following customers were eligible to participate. In order to achieve the conservation savings that occur in the service territories of full-requirements customers, BPA also needs to undertake the CRC program for BPA's other customers who pay for CRC costs. In order for BPA and it's customers to meet their portion of the NWPPC's regional targets, the total expenditures for CRC are required to be incurred.

4. BPA's market transformation efforts are being achieved through the Northwest Energy Efficiency Alliance (NEEA) during the 2009-2013 period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA is projected to pay for approximately one-half of NEEA's operating budgets during this time frame. The expenditures that BPA pays NEEA has only a partial impact on reducing the Administrator's load obligation. The market transformation savings were reduced by seventy percent for the years 2002-2004 and by sixty-seven percent for years 2005-2013, see the calculation at Note 3 to the work sheet "BPA 1982-2007 Programmatic Conservation - After Adjustments." The amount of market transformation expenditures were not reduced. The reason for this is the fact that the amount that BPA is projected to pay NEEA is so material in amount, that it is critical in sustaining market transformation efforts in the region. In order to achieve the thirty-three percent of savings that were included in the savings total, BPA would have needed to fund the program at approximately the same level.

5. The Net Conservation Savings for the years 2008-2013 are outlined on the worksheet titled, "BPA Projected Conservation Program Savings - 2008-2013 - Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts."

BPA's Wholesale Power 2007 Supplemental Rate Case
BPA Projected Conservation Program Savings - 2008-2013
Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts
aMW[1]

	2008	2009	2010	2011	2012	2013	Cumulative Totals
Projected Conservation Program - Gross Saving Amounts:							
CRC - Non-decrement[2]	10.6	10.6	8.5	8.5	8.5	8.5	55.2
CRC - Equivalent-decrement[2]	9.4	9.4	7.5	7.5	7.5	7.5	48.8
Conservation Acquisition - Bi-lateral Contracts	22.0	22.0	28.0	28.0	28.0	28.0	156.0
Market Trans.- Non-decrement[3]	6.7	6.7	8.0	8.0	8.0	8.0	45.4
Market Trans.- Equivalent-decrement[3]	3.3	3.3	4.0	4.0	4.0	4.0	22.6
Total Proj. Conservation Savings	52.0	52.0	56.0	56.0	56.0	56.0	328.0
Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts:							
Less CRC Non-Decrement[2]	(10.6)	(10.6)	(8.5)	(8.5)	(8.5)	(8.5)	(55.2)
Less Market Trans.- Non-decrement[3]	(6.7)	(6.7)	(8.0)	(8.0)	(8.0)	(8.0)	(45.4)
Net Conservation Savings for Section 7(b)(2)	34.7	34.7	39.5	39.5	39.5	39.5	227.4

BPA's Wholesale Power 2007 Supplemental Rate Case
BPA Projected Conservation Program Savings - 2008-2013
Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts

Notes - Adjustments Made to BPA's Conservation Program Savings Amounts to Arrive at Savings Available to Reduce Loads per the Section 7 (b)(2) Rate Test

'1. The conservation saving projections for 2008-2013 come from BPA's program budgets for those years. The conservation saving projections for the years 2009-2011 come from BPA's Conservation Program Proposals that were finalized in the Integrated Program Review process. The saving projections for 2012-2013 were based on the assumption that the conservation program design for 2009-2011 continued during these two years.

2. BPA's post -2006 Conservation Program has provided additional compliance requirements surrounding the CRC program to help ensure the achievement of conservation savings associated with the granting of CRC credits. The majority of CRC expenditures are received by non-load following utilities that purchase the Slice and and Flat-Block power products. The Administrator's load obligations to these utilities has not been reduced, (contract power amounts have not been decremented for the conservation savings) thus BPA will not receive a direct benefit from CRC expenditures associated with non-load following customers during the Section 7(b)(2) rate test period. BPA does receive a direct benefit from load following customers associated with the conservation that occurs in those utility's service territories. Because of the additional controls surrounding the achievement of conservation savings during the post 2006 time period, and because BPA does receive a direct benefit from expenditures that occur in load following utility service territories, the portion of the CRC savings attributable to load following utilities has been included in the Section 7(b)(2) resource stack. The reduction in conservation savings attributable to the CRC program that are not available to the Section 7(b)(2) resource stack for savings occurring in non-load following customer areas is estimated at fifty-three percent. No adjustment to the annual expenditures have been made as explained by Note 3, to the worksheet "Projected Conservation GROSS and NET Section 7 (b)(2) Amounts Expenditure Amounts - 2008-2013."

3. BPA's market transformation efforts are being achieved through the Northwest Energy Efficiency Alliance (NEEA) for during the 2007-2013 period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA is projected to pay for approximately one-half of NEEA's operating budgets during this time frame. The expenditures that BPA pays NEEA has only a partial impact on reducing the Administrator's load obligation. The market transformation savings were reduced by sixty-seven percent, see this calculation at Note 3 to the work sheet "BPA 1982-2004 Programmatic Conservation - After Adjustments." This same level of adjustment in annual savings that applied to 2002-2006 also applies to the period 2007-2013.

4. In summary, the following adjustments were made to the conservation savings projected for the years 2008-2013:

Market Transformation Saving	45.4	aMW
C&RD Savings	55.2	aMW
	100.6	aMW

The total conservation savings projected for BPA's Conservation Program for FY's 2008-2013 is 328.0aMW. The total savings included in the 7(b)(2) resource stack for those years was 227.4 aMW.

BPA's Wholesale Power 2007 Supplemental Rate Case
BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures
BPA 2007 Rate Case 7(b)(2) Resource Stack - Annual Investments and Savings
Nominal Dollars Corresponding to the Historical Year of Acquisition

($ 000)

	Conser. Savings aMW[2,]		Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Capitalized Amortization Period Years
1999 Conser.	30.3		20,657.0	19,728.0	40,385.0	15
2000 Conser.	14.7		15,377.0	347.0	15,724.0	15
2001 Conser.	18.5		19,905.0	57.0	19,962.0	15
2002 Conser.	25.7		17,143.0	28,227.0	45,370.0	15
2003 Conser.	24.7		17,286.0	22,900.0	40,186.0	15
2004 Conser.	31.0		15,821.0	19,431.0	35,252.0	15
2005 Conser.	20.0		22,446.0	14,750.0	37,196.0	15
2006 Conser.	30.2		28,014.0	14,970.0	42,984.0	15
2007 Conser.	28.5		38,860.0	10,725.0	49,585.0	15
2008 Conser.	34.7		71,724.0	15,000.0	86,724.0	15
2009 Conser.	34.7		73,932.0	32,000.0	105,932.0	15
2010 Conser.	39.5		84,804.0	56,000.0	140,804.0	15
2011 Conser.	39.5		85,504.0	56,000.0	141,504.0	15
2012 Conser.	39.5		88,548.0	56,000.0	144,548.0	15
2013 Conser.	39.5		89,292.0	56,000.0	145,292.0	15
Cumulative Savings 1999-2013	**451.0**	aMW	**$689,313.0**	**$402,135.0**	**$1,091,448.0**	
Percentages			**63.16%**	**36.84%**	**100.00%**	

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